California State Fire Marshal

Hazardous Liquid Pipeline Risk Assessment

OFFICE OF STATE FIRE MARSHAL

Pete Wilson
Governor

Sandra R. Smoley
Secretary, State and Consumer Service Agency

Ronny J. Coleman
State Fire Marshal

We are pleased to present this Hazardous Liquid Pipeline Safety Risk Assessment Study and hope that it will be useful to pipeline operators, governmental regulators and public policy-makers at all levels.

The genesis of this work was two State laws passed in 1989: AB 385 authored by Assembly-member Dave Elder, and SB 268 by Senator Herschel Rosenthal. These two bills were introduced in the aftermath of a deadly pipeline rupture and fire which occurred in San Bernardino, California. These laws called for differing studies of hazardous liquid pipeline failures vis-a-vis various risk factors. The called-for studies are combined in this document.

This report is based on 10 years (1981-1990) of pipeline failure/leak data in California. We are highly indebted to the operators of liquid pipelines in California, without whose time-consuming efforts and cooperation this report would not exist. A more specific acknowledgment of these operators is at the back of the report. Providing key and valued guidance throughout the life of this project were members of the Pipeline Safety Advisory Committee.

We also would like to thank our consultant on the project, EDM Services, and Brian Payne who was lead author of this report.

For more information concerning the State Fire Marshal's Pipeline Safety Program, please contact:

CDF/State Fire Marshal
Pipeline Safety Division
PO Box 944246
Sacramento, CA 94244-2460
916/445-8477

California State Fire Marshal
Pipeline Safety Advisory Committee

Joan Jennings, Chair
Deputy Chief
California State Fire Marshal

Dave Elder
Past Assemblyman
Author of California Pipeline Safety Act

Jim Hilliard
Insurance Agent
State Farm Insurance Company

Chris Hunter
Fire Chief
Long Beach Fire Department

James Nowinski
Manager, Pipeline Engineering
Unocal Pipeline

Ken Peterson
Supervisor, 4th District
Kern County

Bob Wilson
Chief
Santa Fe Springs Fire Department

David Wright
Vice President, Western Region
GATX Terminals Corporation

Jerry Englehardt (Past Member)
Vice President Engineering
Santa Fe Pacific Pipeline

Jack Woycheese (Past Member)
Principal
Gage-Babcock and Associates

Matt Rezavani (Technical Advisor)
Consultant
Arco Transportation Company

James Wait, Staff
Division Chief
California State Fire Marshal

California State Fire Marshal
Staff Acknowledgements

Joan Jennings
Deputy Director

James Wait
Division Chief

Charles J. Samo
Supervising Pipeline Safety Engineer

Robert G. Gorham
Project Coordinator

Notice

This document was prepared by EDM Services, Inc., under contract to the California State Fire Marshal. Data was furnished by the pipeline operators. EDM Services, Inc., the California State Fire Marshal, and their staffs do not:

- warrant the accuracy or completeness of the data collected, nor
- assume any liability resulting from the use of, or damage resulting from any information presented herein.

EDM Services, Inc. and the California State Fire Marshal do not endorse products or manufacturers. Trade or manufacturers' names appear herein solely because they are considered essential to the objectives of this study.

California State Fire Marshal

Hazardous Liquid Pipeline Risk Assessment

March 1993

This study was conducted and this document was prepared by:

EDM Services, Inc.
40 West Cochran, Suite 112
Simi Valley, California 93065
Telephone (805) 527-3300
FAX (805) 583-1607

California State Fire Marshal
Hazardous Liquid Pipeline Risk Assessment

Contents

List of Tables

Executive Summary

This report is intended to meet the requirements of the California Government Code Sections 51015 and 51016. It analyzes the risks associated with California's 7,800 miles of regulated hazardous liquid pipelines utilizing leak incident data from January 1981 through 1990.

The study was conducted by EDM Services, Inc. of Simi Valley, California. Brian L. Payne served as project manager and authored the report, except for Section 5.0 which he co-authored. Dr. Michael O'Rourke co-authored Section 5.0 and performed the seismic risk analysis. Shawn Kanaiaupuni performed the statistical analyses.

Extensive efforts were taken to collect data which would allow the results to be presented in meaningful units. The resulting incident rates have been presented in units of *incidents per 1,000 mile years*. This unit provides a means of predicting the number of incidents expected for a given length of line, over a given period of time. For example, if one considered an incident rate of 1.0 incidents per 1,000 mile years, one would expect one incident per year on a 1,000 mile pipeline. Using this unit, frequencies of occurrence can be calculated for any combination of pipeline length and time interval.

Using all available data, the overall incident rates for various pipeline events have been estimated as follows:

California Regulated Hazardous Liquid Pipelines
January 1981 through December 1990 Data

Event	Incident Rate
any size leak	7.1 incidents per 1,000 mile years
damage greater than $5,000	1.3 to 6.2 incidents per 1,000 mile years
damage greater than $50,000	up to 4.4 incidents per 1,000 mile years
any injury, regardless of severity	0.70 injuries per 1,000 mile years
injury requiring hospitalization	0.10 injuries per 1,000 mile years
fatality	0.02 to 0.04 fatalities per 1,000 mile years

The primary study findings are summarized below and are detailed in the paragraphs which follow:

- Pipelines within 500' of a rail line do not pose a higher risk than those located farther from a railroad.
- External corrosion caused 59% of the leak incidents, followed by third party damage which caused 20%.
- Older pipe and pipelines operated at elevated operating temperatures had significantly higher leak incident rates, primarily affected by increased external

corrosion incident rates.

- Little benefit was found to be associated with the cost of adding additional block valves to California's regulated hazardous liquid pipeline network.

The results indicated a decreasing incident rate trend during the ten year study period. The ordinary least squares line of best fit indicated that *the incident rate was decreasing at the rate of 0.52 incidents per year, per 1,000 mile years of pipeline operation during the study period.* This represents roughly a 7% annual reduction in the number of leak incidents for each year during the study period.

On the other hand, the average cost of damage per incident (including property damage, clean-up, hazardous material disposal, etc.) increased significantly during the ten year period. After normalizing the data to constant 1983 US dollars, the ordinary line of best fit indicated that the average cost per incident increased at the rate of $33,040 ($US 1983) per year. The average damage during the study period was $141,000 per incident. This represents an annual damage cost increase of over 20% per year during the study period. The high average cost, combined with the increasing damage cost trend, have likely provided industry with significant incentives to implement programs aimed at minimizing the potential for hazardous liquid pipeline incidents.

It is important to note that there was a huge difference between the average and median damage values. While the average figure was $141,000, the median value was only $7,200 ($US 1983). Further, 75% of the leak incidents resulted in damage of $38,000 or less. This enormous difference between the average and median values, as well as the other data collected, indicates that a few very costly incidents greatly affected the average value. Specifically, only slightly more than 10% of the incidents resulted in damage greater than the average value.

We did not find a difference between the incident rates for pipelines within 500' of a rail line and pipelines away from rail lines. The specific incident rates for these lines were 6.79 and 6.96 incidents per 1,000 mile years respectively. The data does not indicate that the unfortunate 1989 San Bernardino train derailment was anything but an isolated incident. Similar accidents have resulted from incidents caused by other forms of third party damage, external corrosion, etc. As a result, we do not see a need for additional regulations regarding pipelines near railroad rights-of-way. Further, data available from the National Transportation Safety Board and the Department of Transportation indicate that pipelines are the safest mode of freight transportation. Costly new pipeline regulations would likely result in some volume of pipeline traffic being diverted to a less safe transportation mode. This could result in a net decrease in transportation safety.

94% of the injuries and 100% of the fatalities resulted from only three incidents (only 0.58% of the total number of incidents). Each of these incidents had a different cause. Although the number of incidents was too small to draw any meaningful conclusions, it was interesting to note that all of the injuries and fatalities occurred on petroleum product lines; no injuries or fatalities were observed on crude oil pipelines. (Once again, the reader should be cautioned from drawing any potentially misleading conclusions from this limited data sample.)

External corrosion was by far the largest cause of leak incidents, representing 59% of the total. In recent years, industry and regulatory efforts have focused on preventing third party damage. It may be prudent to redirect some of these efforts and/or increase efforts to reduce external corrosion. Pipe age and operating temperature were found to clearly affect external corrosion leak incident rates. As a result, these factors should receive special attention in any future work. In this study, significant differences in external corrosion leak incident rates were found among the following factors:

- Older pipelines had a significantly higher external corrosion leak incident rate than newer lines.

- Elevated pipeline operating temperatures significantly increased the frequency of external corrosion caused leaks.

- Intrastate lines had a higher external corrosion leak incident rate than interstate pipelines. However, the intrastate lines were generally much older and operated at a higher mean operating temperature.

- Non-common carrier lines (those which generally do not transport hazardous liquids for hire) had a higher external corrosion leak incident rate than common carrier pipelines. But the non-common carrier lines operated at a higher mean operating temperature and were older.

- Crude oil pipelines had a much higher external corrosion leak incident rate than petroleum product pipelines. Once again however, crude pipelines had a much higher mean operating temperature and were slightly older.

- Pipelines within standard metropolitan statistical areas (SMSA's) had a higher external corrosion leak incident rate than pipelines in non-SMSA's.

- The external corrosion leak incident rate was less for pipelines greater than 16" in diameter than it was for smaller lines.

- Although a small sample, pipelines without cathodic protection systems had a drastically higher frequency of external corrosion caused leaks than protected lines.

- In some cases, the pipe specification and type of external corrosion coating affected external corrosion leak incident rates.

Pipe age and operating temperature had a significant effect on the resulting overall incident rates; older pipe and pipelines operated at elevated temperatures had significantly higher incident rates. For example, pipelines constructed before 1940 had a leak incident rate roughly 20 times higher than pipelines constructed in the 1980's. The majority of this difference was due to differences in the external corrosion rates. In addition, pipelines operated above 130°F had external corrosion incident rates 8 to 23 times higher than pipelines operated at ambient temperatures.

It is likely that many of the older lines included in the study had inadequate cathodic protection, by current standards, during their early years of operation. The regulatory requirements for these lines has increased during their operating life. For instance, although some interstate line regulations date back to 1908, many externally coated interstate lines were not required to be cathodically protected until 1973; many externally coated intrastate lines were not required to have protection until 1988. Further, intrastate lines operating by gravity or less than 20% SMYS were not required to have cathodic protection until 1991.

The overall leak incident rate for pipelines within standard metropolitan statistical areas (SMSA) was over three times higher than for non-SMSA areas. However, the average damage and spill size for incidents within SMSA's was less than one-third the figures for non-SMSA's. As one might expect, pipe within SMSA's experienced a higher rate of incidents caused by third party damage, 1.51 versus 0.81 incidents per 1,000 mile years. However, the vast majority of the difference between SMSA and non-SMSA leak incident rates resulted from external corrosion; the external corrosion incident rate within SMSA's was nearly five times greater than for non-SMSA's. Unfortunately, a detailed analysis of these data was beyond the scope of this study. Further study may be warranted to further explore these differences. If further study is performed, it should analyze the possibility of a relationship between the differences in interstate versus intrastate pipeline incident rates and those of SMSA's and non-SMSA's.

Little if any statistical correlation was found between spill size and block valve spacing. We found that 50% of the spill volumes represented only 0.75% of the pipeline volume between adjacent block valves; 80% of the spill volumes were less than 8.5% of the pipeline volume between adjacent block valves. These and other data indicated that other factors (e.g. local terrain, low leak rates, etc.) considerably affected spill volumes. However, a cost benefit analysis was performed using the ordinary least squares line of best fit data anyway. The results indicated little benefit relative to the associated costs for adding any significant number of block valves to the existing California regulated hazardous liquid pipeline network. However, we found that there may be some line segments over about 10 miles long which may benefit from intermediate block valves. These segments must be evaluated individually, considering local terrain and other effects, before any further conclusions can be drawn.

Our survey of pipeline operators and local fire departments yielded a consensus that notifying local affected fire agencies each time pipeline fluid contents changed would not result in significant benefits. The fire departments surveyed indicated that their current programs and contingency plans were adequate to handle foreseen emergencies.

We anticipate somewhere between 13 and 29 leak incidents caused by seismic activity on regulated California hazardous liquid pipelines during a future 30 year period. By simply extrapolating injury and fatality data collected in this study, we would expect seismic activity to cause between one and three injuries and have between a 1 in 6 and 1 in 13 likelihood of causing a fatality during the same future 30 year period. However, the reader should note that the injury and fatality extrapolations were based on a very limited data sample; their statistical relevance is very limited. Further, for the purposes of this study, data were included in the injury category, regardless of severity; these included injuries which required only minor on-site medical treatment and/or observation. As a result, we expect that any injury data presented herein is conservative, when compared to more typical injury definitions.

We did not find a statistical correlation between normal operating pressure and the probability of rupture.

1.0 Introduction

A 1989 train derailment, pipeline rupture and subsequent fire stimulated public concern regarding public safety near rail lines adjacent to hazardous liquid pipelines. One of the results of this incident was the passage of California Assembly Bill 385 (Elder). At about the same time, Senate Bill 268 (Rosenthal) was passed as a result of chronic leaks from one of the oldest crude oil pipelines in Southern California.

This report is intended to meet the requirements of both of these bills. It analyzes California's regulated hazardous liquid pipeline risks utilizing leak incident data from January 1981 through December 1990. The California State Fire Marshal, Pipeline Safety Division intends to use the study results to generate a Legislature Report and to propose refinements to current pipeline safety regulations. The latter may include modification of regulatory guidelines governing the construction, testing, operations, periodic inspection, and emergency operations of state regulated hazardous liquid pipelines.

The study was conducted by EDM Services, Inc. Brian L. Payne served as project manager and authored the report, except for Section 5.0 which he co-authored. Dr. Michael O'Rourke co-authored Section 5.0 and performed the seismic risk analysis. Shawn Kanaiaupuni performed the statistical analyses.

1.1 Regulatory Authority

The California State Fire Marshal (CSFM) exercises safety regulatory jurisdiction over interstate and intrastate pipelines used for the transportation of hazardous or highly volatile liquid substances within California. In 1983, the Pipeline Safety Division was specifically created to administer this effort. Mr. James Wait is the current Division Chief responsible for directing the Division.

In 1987, the CSFM acquired the regulatory responsibility for interstate lines when a state certification was executed with the United States Department of Transportation. In doing so, the Pipeline Safety Division became an agent of the Department of Transportation responsible for ensuring that interstate pipeline operators meet federal pipeline safety standards. Specifically, portions of interstate pipelines subject to the agreement between the United States Secretary of Transportation and the California State Fire Marshal are subject to the federal Hazardous Liquid Pipeline Safety Act of 1979, as reauthorized in 1992, and federal pipeline regulations.

The California State Fire Marshal's responsibility for intrastate lines is covered in the California Pipeline Safety Act of 1981, including amendments.

The CSFM Pipeline Safety Division's responsibilities are therefore twofold:

- First, to enforce federal minimum pipeline safety standards and to enforce compliance with such standards over all regulated interstate hazardous liquid pipelines within California; and

- Secondly, to enforce the above, as well as the California Pipeline Safety Act of 1981, as amended, on regulated hazardous liquid intrastate lines.

1.2 Circumstantial History

On May 12, 1989, a Southern Pacific Transportation Company freight train derailed in San Bernardino, California. On May 25, 1989, 13 days later, a regulated interstate petroleum products pipeline ruptured. The National Transportation Safety Board summarized this incident in their public information report entitled, Railroad Derailment Incidents Involving Pipelines: 1981 - 1990 as follows:

> *"A Southern Pacific westbound train lost its brakes as it headed down the Cajon grade toward San Bernardino. After reaching a speed of over 100 mph the train derailed at a curve adjacent to a residential section of San Bernardino. Derailing cars and engines left the track and literally tumbled into several houses, killing two children and two train crew members. All sixty-nine of the cars and five of the locomotive units were destroyed and four others sustained extensive damage.*
>
> *During the derailment, and later during the movement of heavy equipment to remove the wreckage, a high-pressured gasoline pipeline adjacent to the tracks was damaged and weakened. Less than two weeks after the wreck, the pipeline ruptured and spewed over 300,000 gallons of flaming gasoline into the neighborhood, resulting in two more deaths, serious burns to three others, and the destruction of eleven more homes and 21 vehicles. Total damage to the train and track alone was estimated to be well over nine million dollars with an additional damage estimate to the neighborhood of over five million dollars."*

The extremity of this incident stimulated a good deal of public concern. As a result, steps were taken to determine that public safety was not being endangered by the proximity of pipelines to rail lines. One of the results was the passage of California Assembly Bill 385 (Elder).

California Senate Bill 268 (Rosenthal), which was signed by the Governor at the same time, resulted from chronic leaks from one of the oldest crude oil pipelines in the Los Angeles area. These bills included requirements for the State Fire Marshal to perform certain studies which address the risk levels associated with hazardous liquid pipelines on railroad rights-of-way and other factors. Among other things, they required the State Fire Marshal to:

- Study the spacing of shut-off valves that would limit spillage into standard metropolitan statistical areas and environmentally sensitive areas and, if existing standards were deemed insufficient, to adopt regulations to require the addition of new valves on existing, and new or replacement pipelines.

- Conduct and prepare a risk assessment study dealing with hazardous liquid pipelines which were located not more than 500 feet from any rail line.

- Adopt regulations governing the construction, testing, operations, periodic inspections, and emergency operations of intrastate hazardous liquid pipelines located within 500 feet of any rail line.

These investigations are intended to identify which factors pose the greatest risk to people and the environment due to the likelihood of and the probable severity of a hazardous liquid pipeline accident due to corrosion, third party damage, defect, or other causes.

1.3 Relative Safety Perspective

Before we analyze the risks associated with California's hazardous liquid pipelines, it is important to put the relative safety of pipelines versus other modes of transportation into perspective. The United States Department of Transportation, Research and Special Programs Administration's 1990 National Transportation Statistics - Annual Report provides some useful statistics in this regard.

During 1988, there were 49,438 transportation related fatalities in the United States. This data is presented in Table 1-1 by mode of transportation. It should be noted that of the twenty 1988 pipeline fatalities (0.04% of the total domestic transportation fatalities), eighteen of them occurred on gas pipelines. *Only two fatalities resulted from incidents on hazardous liquid pipelines. This represents only 0.004% of the total transportation related fatalities.* (The number of United States hazardous liquid pipeline fatalities per year averaged 3.2 per year for the period from 1978 through 1989.)

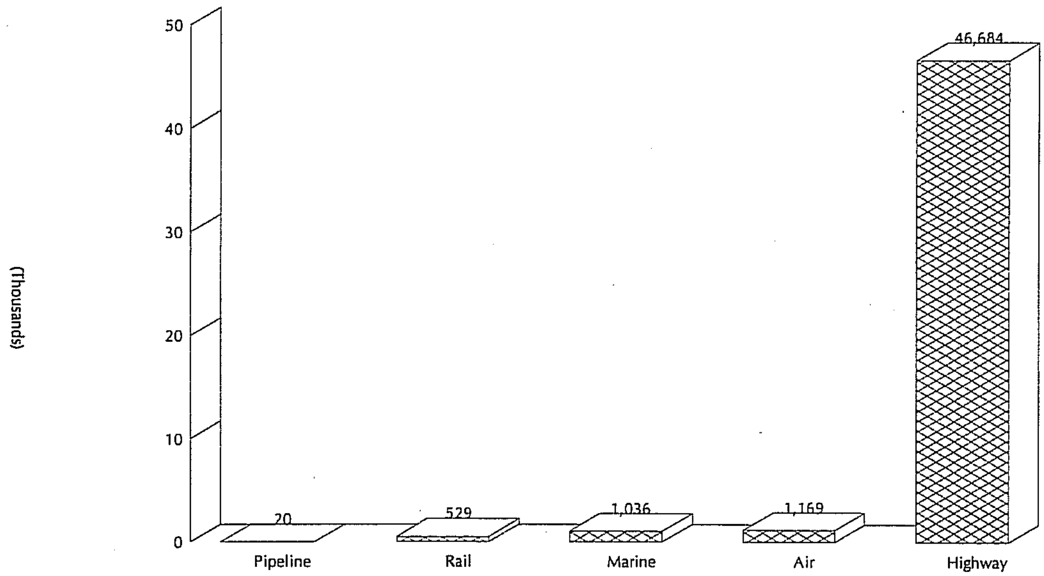
In an attempt to compare the relative safety of each transportation mode, we have estimated the fatality rate per billion ton-miles transported. This was done by first determining the number of 1988 fatalities associated with revenue freight. This was performed for each mode of transportation as follows:

- Pipelines - All fatalities were included.

- Rail - All fatalities, including those occurring at grade crossings with vehicular traffic were included.

- Marine - Recreational boating fatalities were excluded.

Table 1-1
Fatalities by Mode of Transportation
1988 National Transportation Statistics



- Air - All general aviation, air taxi, and commuter fatalities were excluded. Since the remaining air carrier data does not differentiate between incidents associated with passenger traffic versus those associated with freight, the resulting number of revenue freight fatalities is unrealistically high.

- Highway - Only truck fatalities were included. Since truck accidents often result in fatalities to those in automobiles, the resulting *truck only* fatality figure is unrealistically low.

The fatality rate was then determined by dividing the number of fatalities by the number of ton-miles transported. The number of fatalities and resulting fatality rates are presented in Tables 1-2 and 1-3. Despite the inherent data errors, the resulting rates provide a very useful method for determining the relative magnitudes of risk to human life. These results are summarized below, using an arbitrarily assigned risk of 1 for pipelines.

• Pipelines	1
• Marine	3
• Rail	40
• Highway	300

In other words, rail transportation results in roughly 40 times more fatalities than pipelines for a given number of ton-miles transported. Order of magnitude comparisons between the other modes could be determined similarly.

A general understanding of these relative risks is essential for those considering regulatory changes which could increase the cost of hazardous liquid pipeline construction, operation, and/or maintenance. Any increases in the shipping costs associated with such changes would likely result in a portion of the throughput being diverted from pipelines to other transportation modes. Since these other modes generally expose the public to a higher risk than pipelines, any such diversion may actually decrease overall transportation safety. For example, if a costly regulation decreased pipeline accidents by say 10%, but diverted some volume to an alternate, less safe mode of transportation, the new result may be a decrease in overall transportation safety.

There are already signs of this occurring, especially in Southern California. The crude from many of the older production fields which was historically transported by pipeline, has been diverted to truck transportation which has the worst safety record.

Table 1-2
Estimated 1988 Fatalities Associated with Revenue Freight By Mode of Transportation

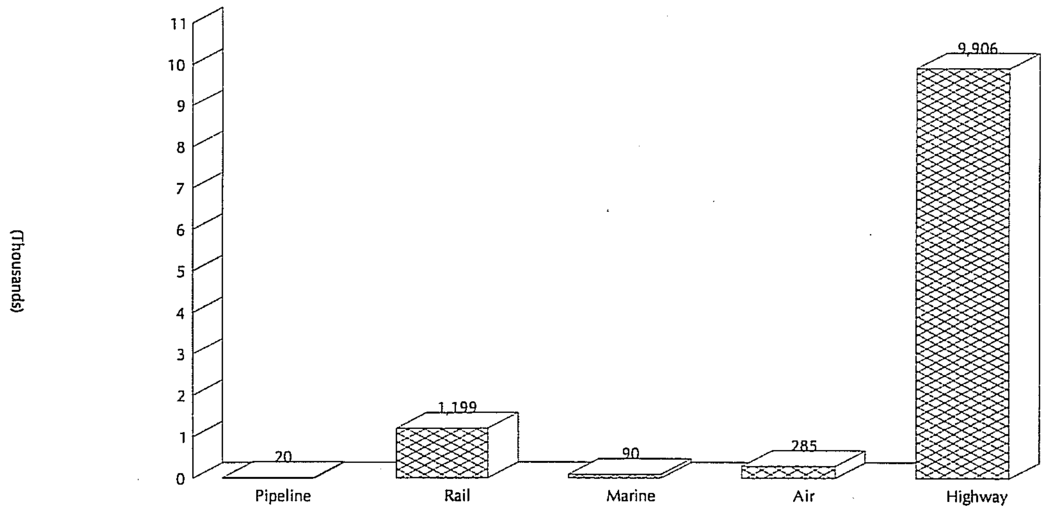
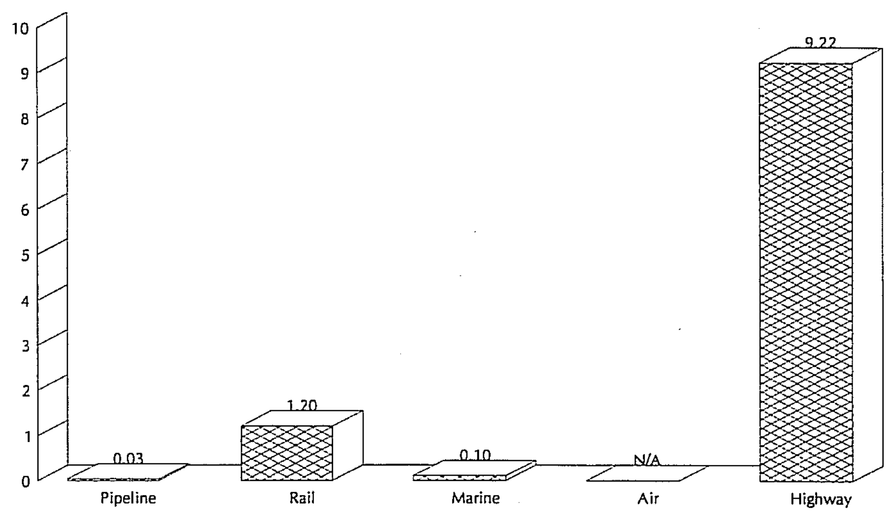


Table 1-3
Estimated 1988 Fatalities Per Billion Ton-Miles Transported By Mode of Transportation



1.4. Acknowledgements

The detailed analyses and data contained in this report could not have been gathered and presented without the full support and cooperation from each of the pipeline operators. EDM Services and the California State Fire Marshal staffs sincerely appreciate each operator's commitment to pipeline safety as evidenced by their time, effort and financial expenditures made to help compile this data. We have attempted to acknowledge the key contacts from each pipeline operating company who worked directly on this project in Exhibit 1; we apologize in advance for any omissions.

We would also like to acknowledge the Pipeline Safety Division staff for their dedication and assistance with these studies. Without their support and occasional prodding, we may never have completed this extensive effort. Specifically, we would like to acknowledge the efforts of Mr. James Wait, Division Chief; Mr. Chuck Samo, Supervising Engineer, and Mr. Robert Gorham, Associate Engineer.

2.0 Methodology

The methodology used to complete these studies is outlined below:

- The California State Fire Marshall, Pipeline Safety Division contracted EDM Services, Inc. to conduct the pipeline studies.

- A Preliminary Questionnaire, requesting detailed pipeline system information, was sent to each pipeline operator. The information requested for *each pipeline unit* included: 1) the accuracy, consistency and availability of in-house leak records; 2) a complete description of each pipeline system, including operational information and pipe inventory; 3) the dates of all hydrostatic tests and cathodic protection surveys; 4) the extent of preventative maintenance performed; 5) leak detection system information; 6) block valve spacing information; etc.

- The pipeline operators forwarded completed Preliminary Questionnaires to EDM Services offices. They were used to verify the pipeline inventory, leak data and other information. This system of verification was intended to assure the greatest possible degree of accuracy and reliability of the results reported herein.

- Leak incident data were personally collected from each pipeline operator by an EDM Services representative. During the field visit to the various pipeline operator offices, in-house leak records were audited and information from them was verified and augmented to the fullest extent possible. It should be noted that *all recorded leaks that occurred on regulated pipelines were included in the study*, even if they did not create enough damage or meet other state and/or federal reporting requirements.

- The raw data collected was initially input using Lotus 123. It was subsequently downloaded and analyzed using the SAS statistical software package.

The following subsections 2.1 through 2.10 provide more descriptive information about the detailed steps taken to accomplish each study task. Unless specific, detailed information regarding this methodology is desired, the reader may skip from here, directly to Section 3.0 of this report.

2.1 Contracting

On August 23, 1990 the California State Fire Marshal's office released a request for proposals to conduct two studies. Completed proposals were received by October 12, 1990. The proposals were reviewed and evaluated using a point system as follows:

- 30 Points - Response to Requirements
- 30 Points - Experience and Expertise
- 10 Points - Quality of Proposal Presentation
- 30 Points - Cost Evaluation

Once the proposals had been evaluated and ranked, the top few bidders made oral presentations. An additional 30 points were awarded based on these presentations. The contract was awarded to the highest scoring bidder meeting the State's minority and woman owned business subcontracting requirements, EDM Services.

The final contract was approved on March 6, 1991. The contractual work scope is summarized below:

- identify jurisdictional pipelines located within 500 feet of any rail line,

- identify the geographic location of those pipelines determined above as to urban or rural,

- identify the leak-history of all jurisdictional pipelines and classify as to their location within or outside a 500 foot zone along rail lines, urban, rural, and environmentally sensitive areas,

- analyze historical events for damage to pipelines from derailments,

- identify and analyze the impact of geological or seismic activities on all jurisdictional pipelines,

- analyze the feasibility of testing, repair, replacement and/or relocating pipelines suspected of potential damage resulting from a railroad derailment,

- analyze the feasibility of pipeline operators notifying local affected fire agencies of the contents and any changes in the hazardous liquid being transported, and

- evaluate the best control technology available to protect public safety in the event of a pipeline emergency resulting from a railroad derailment.

The contract *deliverables* were to include the:

- collection, compilation, and analysis of all data,

- characterization of risk levels associated with pipelines in general,

- characterization of risk levels associated with pipelines located within 500 feet of rail lines, and

- preparation of a report based upon the above analyses.

2.2 Pipeline Operator Notification

On April 4, 1991, Mr. James Wait, Division Chief, Pipeline Safety Division, California State Fire Marshal, notified all of the regulated hazardous liquid pipeline operators of the studies being performed by EDM Services. This was done via a letter from Mr. Wait to each of the operators. The notification letter included the following:

- a brief description of the Assembly and Senate bills requiring the studies,

- a statement that the CSFM intended to use the study results to generate a Legislature Report and develop regulations governing the construction, testing, operation, periodic inspection, and emergency operations of hazardous liquid pipelines,

- notification that EDM Services personnel would be visiting each pipeline operator to collect specific leak data, and

- notification that EDM Services would be forwarding questionnaires to each operator soliciting information regarding leak records, pipeline system information, etc.

2.3 Key Contact List and Preliminary Questionnaire

On April 26, 1991 EDM Services forwarded a <u>Preliminary Questionnaire</u>, <u>Key Contact List</u>, and detailed instructions for their completion to each pipeline operator. The <u>Key Contact List</u> was used by each pipeline operating company to identify a key contact(s) within their organization to coordinate the California State Fire Marshal's pipeline safety studies. The Key Contacts for most of the pipeline operators were responsible for the following activities:

- completing and returning the <u>Key Contact List</u>,

- completing and returning the <u>Preliminary Questionnaire</u>, and

- working with EDM Services' field personnel during their visit and review of leak records, alignment sheets, etc.

The completed <u>Key Contact Lists</u> were scheduled to be returned to our office by May 10, 1991. Unfortunately however, many of the forms were several months late.

The Preliminary Questionnaire was comprised of two parts (A and B). Part A was used by our firm to plan and schedule the review of each operating company's leak reports and alignment sheets. It covered general information such as the location(s) of leak records, potential differences in record keeping procedures for interstate versus intrastate lines, criteria for recording leaks in rural versus urban areas, and any changes which may have taken place in the criteria used to record leaks during the study period.

Part B provided very detailed information regarding each pipeline system. Combined with the leak data collected during our field visits, this data was the cornerstone of the studies. As a result, the importance of accurate information was emphasized. Since the data requested was fairly exhaustive, it was anticipated that it would require a significant effort on each operators part to compile.

The Preliminary Questionnaire - Part A's were scheduled to be completed and returned to our office by Friday, May 17th. The Preliminary Questionnaire - Part B's were scheduled to be completed and returned to our office by Friday, May 31st, or upon our visit to each operator's office, whichever was sooner. Unfortunately however, the final completed questionnaires were not received until April 1992, nearly a year late.

2.4 In-House Mapping and Background Information

Prior to gathering the actual leak data during our field visits with each operator, it was necessary to gather a significant amount of background information. These tasks included:

a. Securing a mailing list from the CSFM identifying the initial contacts and addresses of the pipeline operators.

b. Obtaining the CSFM's list of high risk pipelines.

c. Determining the total length of regulated pipeline, the total length within 500' of a rail line, and the total length of pipeline within each County. This was accomplished as follows:

   - A complete set of the CSFM's Thomas Brothers map book overlays was secured.
   - The overlays were reviewed to ensure that the set was complete. Missing overlays were requested from the CSFM.
   - A second *working set* of overlays was made.
   - Drawings showing the main rail lines in the state were secured from the Public Utilities Commission.

- The main rail lines were highlighted in the Thomas Brothers map books on all pages which also had regulated pipelines.

- Each overlay was reviewed and the total pipe length was measured using a planimeter. The length within 500' of a rail line and the length within each County was also measured using a planimeter. The measured lengths for each pipe system were recorded on separate forms, by Thomas Guide page number and county. This data, although subject to some error because of the scale limitation, provided a check for the data received from the pipeline operators.

d. The lengths of pipelines and lengths of pipelines within 500' of rail lines were determined for areas within and outside standard metropolitan statistical areas (SMSA). Since SMSA boundaries, as well as the data gathered in item "c" above, both coincide with county lines, this was relatively easily accomplished. The following table lists the SMSA counties, as well as those which are not SMSA's.

SMSA	Non-SMSA
Alameda	Alpine
Butte	Amador
Contra Costa	Calavaras
Fresno	Colusa
Kern	Del Norte
Los Angeles	El Dorado
Marin	Glenn
Monterey	Humboldt
Napa	Imperial
Orange	Inyo
Placer	Kings
Sacramento	Lake
San Diego	Lassen
San Francisco	Madera
San Joaquin	Mariposa
San Mateo	Merced
Santa Barbara	Mendocino
Santa Cruz	Moduc
Shasta	Mono
Solano	Nevada
Sonoma	Plumas
Stanislaus	Riverside
Sutter	San Benito
Tulare	San Bernardino
Ventura	San Luis Obispo

Yolo	Sierra
Yuba	Siskiyou
	Tehama
	Trinity
	Tuolumne

2.5 Data Gathering Guideline

As specific information became available regarding each pipeline system via the Preliminary Questionnaire - Parts A and B, EDM Services personnel were scheduled to visit each pipeline operator. Their primary objectives were to review the Preliminary Questionnaires with the operator and gather specific leak data for *all* leaks which occurred during the study period. To ensure consistency between the leak data collected and to communicate our staff's work plans with each pipeline operator, a Data Gathering Guideline was written.

This plan was intended to provide written instructions and guidelines for EDM Services' employees. It outlined the firm's intended methodology and provided specific instructions for collecting pipeline leak data. In addition, it gave pipeline operators an indication of what we would be collecting, how we intended to go about collecting it, and what level of involvement would be required from them.

Naturally, the delay in the operators' completion of the Preliminary Questionnaire - Parts A and B, significantly affected EDM Services' schedule for visiting each pipeline operator. Some of this work was delayed for nearly a year beyond the original schedule.

2.6 Gather Railroad and Public Utilities Commission Data

Since one of the primary study goals was to ascertain the relative risk level of pipelines near railroads versus those outside railroad areas. It was necessary to gather data regarding train derailments. This was accomplished as follows:

- Train derailment information was obtained from the Public Utilities Commission and National Transportation Safety Board for the period from January 1, 1981 through December 31, 1990.

- The accident reports were reviewed to determine the cause of derailment, extent of pipeline damage, and the type of rail line.

2.7 Conduct Pilot Surveys

A few pipeline operators were selected to participate in a pilot survey. This phase was intended to give us an opportunity to refine our general approach, forms and procedures early in the study. The selected operators were notified two to three weeks before our scheduled field visit. This task proceeded as described below:

a. Arrange Visit

The field visits with the selected pilot study participants were handled as follows:

- The operators were notified that they had been selected to participate in the pilot study.
- EDM Services staff worked with the selected operators to expedite completion of their Key Contact List and Preliminary Questionnaires.
- Field visits were scheduled to coincide with the operators' completion of their Preliminary Questionnaires.
- Key Contacts were confirmed to be available to help our staff review the operating company's leak records, alignment sheets, etc.

b. Review Key Contact List and Preliminary Questionnaire Responses

Prior to the field visit, these documents were reviewed. This review included:

- The Key Contact Lists were reviewed for completeness. We ensured that each operating company had completed a separate list for each CSFM Inspection Unit Number. We also verified that all of the regulated pipeline systems had been assigned to a key contact.
- Preliminary Questionnaire - Part A

  The returned forms were reviewed for completeness. We ensured that separate questionnaires had been completed for each CSFM Inspection Unit Number. We also verified that leak record storage locations had been provided for each of the regulated pipeline systems.

- Preliminary Questionnaire - Part B

  These forms were reviewed for completeness. We ensured that separate questionnaires had been completed for each regulated pipeline system. Any incomplete responses were referred to the company's key contact. The total pipeline length, and the length of line within 500' of a rail line were checked against our in-house data which was obtained as outlined earlier.

c. Visit Pilot Operating Companies

An EDM technician and principal visited each selected pilot operating company. The visits proceeded as follows:

- Any outstanding questions from the Preliminary Questionnaires were resolved.

- We provided an overview of the data we wished to collect and the methods we planned to use.

- We reviewed the operating company's leak records for the study period. A separate Leak Data Form was completed for each leak reviewed. Alignment sheets, cathodic protection surveys, hydrostatic tests, and other records were reviewed as necessary to properly complete the Leak Data Forms. As a result, it was necessary to work with an operating company representative to gather all of the necessary data.

d. Evaluate and Refine Data Collection Guideline

Based on our experience with the pilot operating companies, the Data Collection Guideline was revised as necessary.

2.8 Gather Data From Remaining Operating Companies

After the pilot study had been conducted and as completed Preliminary Questionnaires were received, visits were scheduled with each of the operating companies. This work proceeded as discussed earlier for the pilot operating companies.

2.9 Statistical Analysis

The raw data collected were initially entered using Lotus 123. They were subsequently downloaded and analyzed using the SAS and STATA statistical software packages. Descriptive statistics were performed using incident rate units of *incidents per 1,000 mile years*. These incident rates were determined by dividing the number of incidents by the number of mile years of pipeline operation for a given category of data. Thus for all pipelines built before the commencement of the study, which continued in operation through the study period, the number of mile years was determined by multiplying the pipe length by the ten year study period. For pipelines built sometime during the study period, the number of mile years was determined by multiplying the pipeline length by the actual number of years of operation during the study period.

The dichotomous probability of an incident occurring was determined using logistic regression analysis. We controlled for various factors, such as pipe age, to determine the independent effects of variables on the probability of a leak incident. The independent variables considered included operating temperature and flow, operating pressure, type of cathodic protection system, interstate versus intrastate pipeline, etc.

2.10 Potential Data Inconsistencies

The importance of an accurate pipeline inventory on the study results can't be overemphasized; the inventory data directly affects the calculated incident rates since it is used in the denominator of the incident rate equation. For example, a ten percent error in the pipeline inventory alone would result in a corresponding ten percent error in the calculated incident rate. As a result, a laborious mapping effort was undertaken to verify the data furnished by the pipeline operators on their Preliminary Questionnaires. (See also Section 2.4 presented earlier for a detailed description of this methodology.)

The pipeline inventory data gathered through EDM Services' mapping effort was then compared with the data furnished by each pipeline operator, for every pipeline included in the study. Finally, a significant effort was undertaken to resolve the inherent discrepancies between the mapped data and the information furnished by the operators. Once completed, the total pipeline length information was resolved to within 0.0%. The length of pipeline within 500' of a rail line was resolved to within 1.7%. These values are much smaller than originally anticipated.

Since the reporting criteria for leaks on interstate and intrastate pipelines varied during the study period, we were concerned that the operators' criteria for keeping leak records may have varied as well. This would have caused significant problems during data analysis. For example, if the criteria for keeping leak records became more stringent during the study period, the resulting data would have falsely indicated that the actual leak incident rates were increasing.

However, we found that with only one exception, all operators had kept records on nearly every leak which had occurred on their lines, regardless of size or severity. Most operators pointed out that this practice had become necessary to enable them to successfully defend claims against them for generating contaminated soil near their pipelines.

An unavoidable limitation of the data included:

- leaks reported on pipeline units which were not functioning when we collected pipeline and/or leak data and

- leaks which occurred on pipe segments which had been replaced during the study period.

As a result, the general information parameters such as fluid contents, pipe length, operating temperature, operating pressure, diameter, and other factors used to calculate incident rates and generate statistically reliable results were unavailable for some of the original pipe segments where the leak occurred. Data regarding the original pipe where the leak occurred was restricted in these cases to that which existed on the operator's leak record. Obviously, statistical analyses in these instances are limited and we believe that any resulting errors or uncertainties are relatively insignificant.

Since the record keeping practices for leaks which occurred during hydrostatic testing were inconsistent between pipeline operators, all leaks that occurred during hydrostatic testing were deleted from the analyses. Additionally, information from one pipeline operator was completely deleted from the study after we determined that its records did not meet our standards of accuracy.

3.0 Background Pipeline Risk Data

A number of sources are available for pipeline incident data. Unfortunately however, few of them include the reliable pipeline inventory necessary to determine meaningful incident rates. In this study, we have included results from the following sources:

- CONCAWE Oil Pipelines Management Group's Special Task Force on Pipeline Spillages (OP/STF-1). Performance of Oil Industry Cross Country Pipelines in Western Europe, Statistical Summary of Reported Spillages. 1981 to 1989 annual reports.

- Line Pipe Research Supervisory Committee of the Pipeline Research Committee of the American Gas Association. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines 1970 Through June 1984, NG-18 Report Number 158. 1989.

- Line Pipe Research Supervisory Committee of the Pipeline Research Committee of the American Gas Association. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines June 1984 Through 1989, NG-18 Report Number 196. 1989.

- United States Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety. Annual Report on Pipeline Safety. 1986 through 1989 annual reports.

Each of these reports provide pipeline incident data for *reportable* incidents. Unfortunately however, the criteria for *reporting* incidents differs for each study. This makes direct comparison of the individual results difficult. On the other hand, it provides a methodology for estimating incident rates for spills meeting various criteria.

The following subsections provide a summary of the data contained in each of these reports. The incident rates are shown in units of *incidents per 1,000 mile years*. This unit provides a means for predicting the number of incidents expected for a given length of line, over a given period of time. For example, if one considered an incident rate of 1.0 incidents per 1,000 mile years; one would expect one incident per year on a 1,000 mile pipeline. If the pipeline was only 1 mile long, one would expect 1/1,000th of an incident per year, or an incident every 1,000 years. Using these units, frequencies of occurrence can be calculated for any pipeline length and/or time interval.

3.1 CONCAWE - 1981 Through 1989

We have summarized the pipeline results for western European pipelines, as presented in the CONCAWE Performance of Oil Industry Cross Country Pipelines In Western Europe, Statistical Summary of Reported Spillages, 1981 through 1989 annual reports in Table 3-1.

Table 3-1
European Hazardous Liquid Pipeline Incidents As Reported By CONCAWE 1981 through 1989

	1981	1982	1983	1984	1985
Total Pipeline Mileage	11,737	11,364	11,240	10,743	10,805
Number of Incidents	16	10	10	13	7
Incident Rate (Incidents/1,000 Mile Years)	1.36	0.88	0.89	1.21	0.65
Number of Injuries	0	0	0	0	0
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.000	0.000	0.000	0.000
Number of Fatalities	0	0	0	0	0
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.000	0.000	0.000

	1986	1987	1988	1989	Total
Total Pipeline Mileage	10,805	10,805	10,992	11,737	100,228
Number of Incidents	12	8	11	13	100
Incident Rate (Incidents/1,000 Mile Years)	1.11	0.74	1.00	1.11	1.00
Number of Injuries	0	0	0	1	1
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.000	0.000	0.085	0.010
Number of Fatalities	0	0	0	3	3
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.000	0.256	0.030

Reportable incidents include:
1. All leaks greater than one cubic meter (264 gallons or approximately 6 barrels).
2. All leaks under one cubic meter which resulted in noteworthy environmental impact.

The criteria for including hazardous liquid pipeline incidents in these reports are as follows:

- all spills greater than one cubic meter (approximately 264 gallons or 6 barrels) and

- spills less than one cubic meter, if the spill had a noteworthy impact on the environment.

It is interesting to note that this reporting criteria does not include any consideration for incidents which cause injuries and/or fatalities. As a result, the injury and fatality incident rates derived from this data may be low. Also, the overall incident rates for these relatively large spills is comparatively low, as shown below:

• Incident Rate	1.00 incidents per 1,000 mile years
• Injury Rate	0.010 injuries per 1,000 mile years
• Fatality Rate	0.030 fatalities per 1,000 mile years

3.2 U.S. Natural Gas Transmission and Gathering Lines, 1970 Through June 1984

Table 3-2 presents the reportable domestic natural gas transmission and gathering line incidents from 1970 through June 1984. The criteria for leaks to be reported to the Department of Transportation for inclusion in this data are as follows:

- resulted in a death or injury requiring hospitalization,
- required the removal from service of any segment of a transmission pipeline,
- resulted in gas ignition,
- caused an estimated damage to the property owner, or of others, or both, of $5,000 or more,
- involved a leak requiring immediate repair,
- involved a test failure that occurred while testing either with gas or another test medium, or
- in the judgement of the operator, was significant even though it did not meet any of the above criteria.

The incident rates for reported leaks meeting this criteria are summarized below:

• Incident Rate	1.30 incidents per 1,000 mile years
• Injury Rate	0.096 injuries per 1,000 mile years
• Fatality Rate	0.016 fatalities per 1,000 mile years

Table 3-2
U. S. Natural Gas Transmission and Gathering Lines
Reportable Incidents
1970 through June 1984

	1970	1971	1972	1973	1974	1975
Total Pipeline Mileage	284,196	285,482	285,575	285,241	293,885	267,079
Number of Incidents	343	409	409	471	458	366
Incident Rate (Incidents/1,000 Mile Years)	1.21	1.43	1.43	1.65	1.56	1.37
Number of Injuries	24	24	37	19	21	21
Injury Rate (Injuries/1,000 Mile Years)	0.084	0.084	0.130	0.067	0.071	0.079
Number of Fatalities	1	3	6	2	4	7
Fatality Rate (Fatalities/1,000 Mile Years)	0.004	0.011	0.021	0.007	0.014	0.026

	1976	1977	1978	1979	1980
Total Pipeline Mileage	277,555	283,373	303,355	311,098	388,857
Number of Incidents	254	445	444	482	325
Incident Rate (Incidents/1,000 Mile Years)	0.92	1.57	1.46	1.55	0.84
Number of Injuries	42	22	30	96	16
Injury Rate (Injuries/1,000 Mile Years)	0.151	0.078	0.099	0.309	0.041
Number of Fatalities	7	8	1	12	1
Fatality Rate (Fatalities/1,000 Mile Years)	0.025	0.028	0.003	0.039	0.003

	1981	1982	1983	1984 (3)	Total
Total Pipeline Mileage	400,243	342,645	346,355	157,921	4,512,860
Number of Incidents	389	390	473	204	5,862
Incident Rate (Incidents/1,000 Mile Years)	0.97	1.14	1.37	1.29	1.30
Number of Injuries	6	41	25	11	435
Injury Rate (Injuries/1,000 Mile Years)	0.015	0.120	0.072	0.070	0.096
Number of Fatalities	6	10	2	2	72
Fatality Rate (Fatalities/1,000 Mile Years)	0.015	0.029	0.006	0.013	0.016

Notes:
1. 36 of the total 72 fatalities were to employees of the operating company.
2. 161 of the total 274 injuries were to employees of the operating company.
3. The 1984 mileage figure shown is one-half the actual mileage to account for only one-half year of data.

Reportable incidents include:
1. Resulted in a death or injury requiring hospitalization.
2. Required the removal from service of any segment of a transmission pipeline.
3. Resulted in gas ignition.
4. Caused an estimated damaged to the property of the operator, or of others, or both, of $5,000 or more.
5. Involved a leak requiring immediate repair.
6. Involved a test failure that occurred while testing either with gas or another test medium.
7. Or, in the judgement of the operator, was significant even though it did not meet any of the above criteria.

3.3 U.S. Natural Gas Transmission and Gathering Lines, June 1984 through 1988

Table 3-3 presents the reportable domestic natural gas transmission and gathering line incidents from June 1984 through 1988. It is important to note that in June 1984, the Department of Transportation changed the criteria for reporting leaks. The most significant change was that in general, leaks causing less than $50,000 property damage, did not have to be reported. Since this value is significantly greater than the $5,000 criteria for the earlier study period, we see a significant decrease in the resulting *reportable* incident rate. Although impossible to verify using this data, we also believe that the actual frequency of incidents decreased during this period as a result of one-call system implementation, among other things.

The criteria for leaks to be reported to the Department of Transportation from June 1984 through 1988 were as follows:

- Events which involved a release of gas from a pipeline, or of LNG or gas from an LNG facility, which caused: (a) a fatality, or personal injury necessitating inpatient hospitalization; or (b) estimated property damage, including costs of gas lost by the operator, or others, or both, of $50,000 or more.

- An event which resulted in an emergency shut-down of an LNG facility.

- An event that was significant, in the judgement of the operator, even though it did not meet the criteria above.

The incident rates for reported leaks meeting this criteria from June 1984 through 1988 are summarized below:

- Incident Rate — 0.27 incidents per 1,000 mile years
- Injury Rate — 0.062 injuries per 1,000 mile years
- Fatality Rate — 0.015 fatalities per 1,000 mile years

As demonstrated by the approximately 80% reduction in the incident rate over the earlier period, we see that the change in reporting criteria, among other things, had a major influence on the results. However, it is interesting to note that the injury and fatality rates remained nearly unchanged from the earlier period.

Table 3-3
Onshore U. S. Natural Gas Transmission and Gathering Lines
Reportable Incidents
June 1984 through 1988

	1984[1]	1985	1986	1987	1988	Total
Total Pipeline Mileage	157,921	324,426	340,202	290,176	310,079	1,422,804
Number of Incidents	60	115	67	60	81	383
Incident Rate (Incidents/1,000 Mile Years)	0.38	0.35	0.20	0.21	0.26	0.27
Number of Injuries	30	12	18	15	13	88
Injury Rate (Injuries/1,000 Mile Years)	0.190	0.037	0.053	0.052	0.042	0.062
Number of Fatalities	7	6	6	0	3	22
Fatality Rate (Fatalities/1,000 Mile Years)	0.044	0.018	0.018	0.000	0.010	0.015

Notes:
1. The 1984 mileage figure shown is one-half the actual mileage to account for only one-half year of data.

Reportable incidents include:
- Events which involve a release of gas from a pipeline, or of LNG or gas from an LNG facility, which cause
  (a) a fatality, or personal injury necessitating inpatient hospitalization; or
  (b) estimated propoerty damage, including costs of gas lost by the operator or others, or both, of $50,000 or more.
- An event which results in an emergency shut-down of an LNG facility.
- An event that is significant, in the judgement of the operator, even though it did not meet the criteria of 1 or 2 above.

3.4 U.S. Hazardous Liquid Pipeline Accidents, 1986 through 1989

As noted earlier, a reliable pipeline inventory is necessary to determine precise incident rates. The degree of accuracy of the domestic hazardous liquid pipeline inventory is questionable. For example, the total reported pipeline length remained constant for each year examined. However, we are aware of new line construction and line abandonments during this period. As a result, *we believe that the incident rates derived using the reported pipeline lengths are approximations only*; they should not be taken as absolute.

Table 3-4 presents the reportable domestic hazardous liquid pipeline incidents from 1986 through 1989. The criteria for incidents to be reported to the Department of Transportation for inclusion in this data were as follows:

- explosion or fire not intentionally set by the operator,
- loss of more than 50 barrels of liquid or carbon dioxide,
- escape to the atmosphere of more than five barrels per day of highly volatile liquid,
- death of any person,
- bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident, and/or
- estimated property damage to the property of the operator, or others, or both, exceeding $5,000.

The approximate incident rates for reported leaks meeting this criteria are summarized below:

- Incident Rate — 1.30 incidents per 1,000 mile years
- Injury Rate — 0.177 injuries per 1,000 mile years
- Fatality Rate — 0.018 fatalities per 1,000 mile years

It's interesting to note that these results are essentially the same as those for reportable U.S. natural gas lines from 1970 through June 1984, which had a similar $5,000 property damage reporting requirement.

Table 3-4
U. S. Hazardous Liquid Pipeline Accidents
Reportable Incidents
1986 through 1989

	1986	1987	1988	1989	Total
Total Pipeline Mileage	150,000	155,000	155,000	155,000	615,000
Number of Incidents	203	237	196	161	797
Incident Rate (Incidents/1,000 Mile Years)	1.35	1.53	1.26	1.04	1.30
Number of Injuries	32	20	19	38	109
Injury Rate (Injuries/1,000 Mile Years)	0.213	0.129	0.123	0.245	0.177
Number of Fatalities	3	3	2	3	11
Fatality Rate (Fatalities/1,000 Mile Years)	0.020	0.019	0.013	0.019	0.018

Notes:
1. The mileage figures are approximate as reported by the U.S. Department of Transportation's, Annual Report on Pipeline Safety, published for each subject year.

After October 21, 1985, reportable incidents include:
- Explosion or fire not intentionally set by the operator.
- Loss of more than 50 barrels of liquid or carbon dioxide.
- Escape to the atmosphere of more than five barrels per day of highly volatile liquid.
- Death of any person.
- Bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.
- Estimated property damage to the property of the operator or others, or both exceeds $5,000.

3.5 Summary California Regulated Hazardous Liquid Pipeline Data - 1981 through 1990

As noted earlier, this study included all regulated California hazardous liquid pipelines. The systems included in this study had complete leak records. *All leaks, regardless of size, extent of property damage, or extent of injury were included in the study.* As a result, the incident rates were much higher than presented in earlier studies, which only included reported leaks fitting a relatively narrow criteria. A summary of these results is included in Table 3-5. The incident rates for *all* leaks during the study period are summarized below:

• Incident Rate (All Leaks)	7.08 incidents per 1,000 mile years
• Incident Rate (> $5,000)	5.33 incidents per 1,000 mile years
• Incident Rate (> $50,000)	4.43 incidents per 1,000 mile years
• Incident Rate (> $500,000)	2.80 incidents per 1,000 mile years
• Injury Rate (any severity)	0.685 injuries per 1,000 mile years
• Fatality Rate	0.042 fatalities per 1,000 mile years

3.6 Comparison of Various Incident Data Sources

Table 3-6 demonstrates the differences that various reporting criteria have on the resulting incident rates. It should be noted that the California incident rates, which appear to be much higher, are the only data which have been completely audited. In addition, as mentioned several times previously, the California data includes *all leaks and injuries, regardless of spill size or injury severity*. These data do *not* necessarily indicate that California's regulated hazardous liquid pipeline network presents a higher risk than those in other areas. In fact, it may pose a lower risk than in other areas. Unfortunately however, we could not find audited data from other areas, with complete leak records, for comparison.

One of the benefits of having data available which met various reporting standards was that incident rates could be established for a variety of criteria. For example, the California data could be used to establish incident rates for *all* leaks and injuries. Data from the other studies could be used to establish incident rates for their specific reporting criteria. These differences are summarized in the following subsection.

Table 3-5
California Regulated Hazardous Liquid Pipeline Data - All Leaks
1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6,482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	53	83	53	30	45	46
Incident Rate (Incidents/1,000 Mile Years)	8.18	12.47	7.94	4.39	6.42	6.13
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.150	0.300	0.000	0.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.000	0.000	0.000	0.133

	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	60	52	42	43	507
Incident Rate (Incidents/1,000 Mile Years)	7.91	6.84	5.52	5.65	7.08
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.000	4.074	0.000	0.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.263	0.000	0.042

Note: The above table includes all leaks, regardless of size or severity.

California Regulated Hazardous Liquid Pipeline Data
Leaks Greater Than 5 Barrels, or Greater Than $5,000 Damage
1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6,482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	52	73	44	30	41	40
Incident Rate (Incidents/1,000 Mile Years)	8.02	10.96	6.59	4.39	5.85	5.33
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.150	0.300	0.000	0.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.000	0.000	0.000	0.133

	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	48	42	35	36	441
Incident Rate (Incidents/1,000 Mile Years)	6.33	5.53	4.60	4.73	6.16
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.000	4.074	0.000	0.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.263	0.000	0.042

Note: The above table also includes all leaks which resulted in any injury, regardless of severity, and all leaks resulting in fatalities.

California Regulated Hazardous Liquid Pipeline Data
Leaks Greater Than $50,000 Damage
1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6,482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	39	56	33	20	31	27
Incident Rate (Incidents/1,000 Mile Years)	6.02	8.41	4.94	2.93	4.43	3.60
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.150	0.300	0.000	0.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.000	0.000	0.000	0.133

	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	34	30	21	26	317
Incident Rate (Incidents/1,000 Mile Years)	4.48	3.95	2.76	3.42	4.43
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.000	4.074	0.000	0.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.263	0.000	0.042

California Regulated Hazardous Liquid Pipeline Data
Leaks Greater Than $500,000 Damage
1981 through 1990

	1981	1982	1983	1984	1985	1986
Total Pipeline Mileage	6,482	6,658	6,675	6,835	7,005	7,501
Number of Incidents	36	50	30	19	28	21
Incident Rate (Incidents/1,000 Mile Years)	5.55	7.51	4.49	2.78	4.00	2.80
Number of Injuries	0	1	2	0	0	15
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.150	0.300	0.000	0.000	2.000
Number of Fatalities	0	0	0	0	0	1
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.000	0.000	0.000	0.133

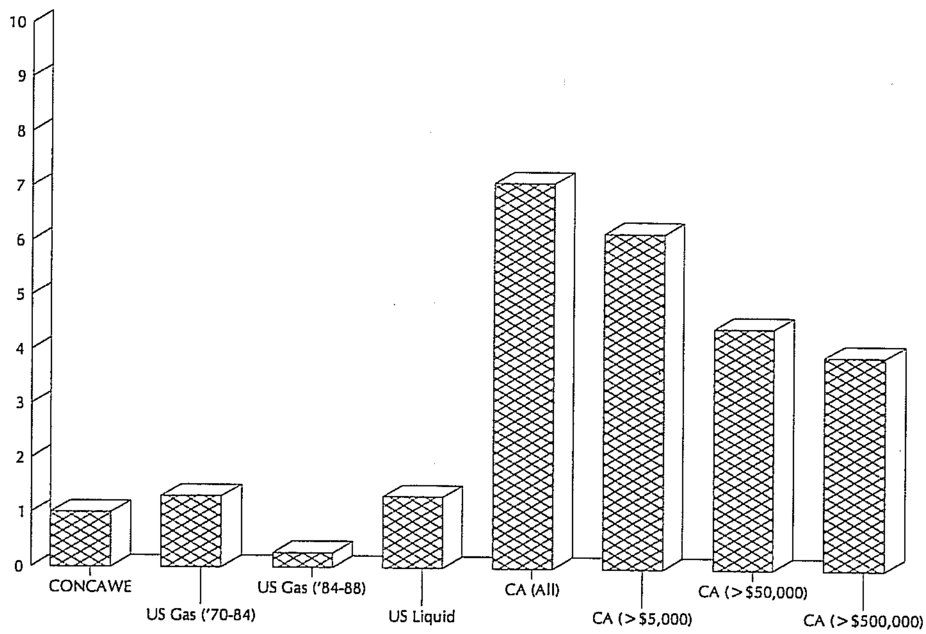
	1987	1988	1989	1990	Total
Total Pipeline Mileage	7,587	7,600	7,609	7,610	71,563
Number of Incidents	31	24	18	24	281
Incident Rate (Incidents/1,000 Mile Years)	4.09	3.16	2.37	3.15	3.93
Number of Injuries	0	0	31	0	49
Injury Rate (Injuries/1,000 Mile Years)	0.000	0.000	4.074	0.000	0.685
Number of Fatalities	0	0	2	0	3
Fatality Rate (Fatalities/1,000 Mile Years)	0.000	0.000	0.263	0.000	0.042

Note: The above tables also include all leaks which resulted in any injury, regardless of severity, and all leaks resulting in fatalities.

Table 3-6
Comparison of Various Incident Data Sources
All Data Presented In Incidents Per 1,000 Mile Years

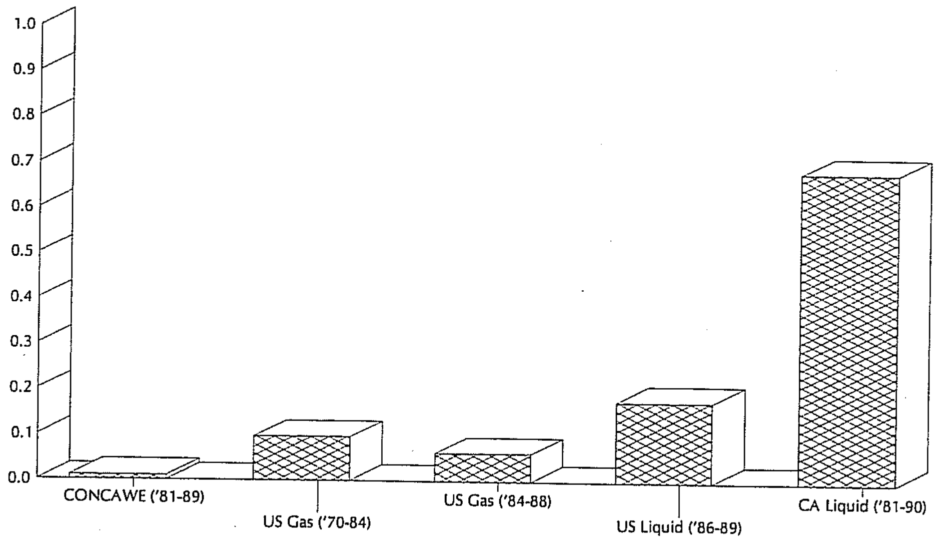
	Incident Rate	Injury Rate	Fatality Rate
CONCAWE - 1991 to 1989	1.000	0.010	0.030
U.S. Natural Gas - 1970 to 1984	1.300	0.096	0.016
U. S. Natural Gas - 1984 to 1988	0.270	0.062	0.015
U. S. Hazardous Liquid - 1986 to 1989	1.300	0.177	0.018
California (all leaks) - 1981 to 1990	7.080	0.685	0.042
California (leaks > 5bbl, or > $5,000) - 1981 to 1990	6.162	0.685	0.042
California Leaks (> $50,000) - 1981 to 1990	4.430	0.685	0.042
California Leaks (> $500,000) - 1981 to 1990	3.927	0.685	0.042

Incident Rate Comparison
Incidents Per 1,000 Mile Years

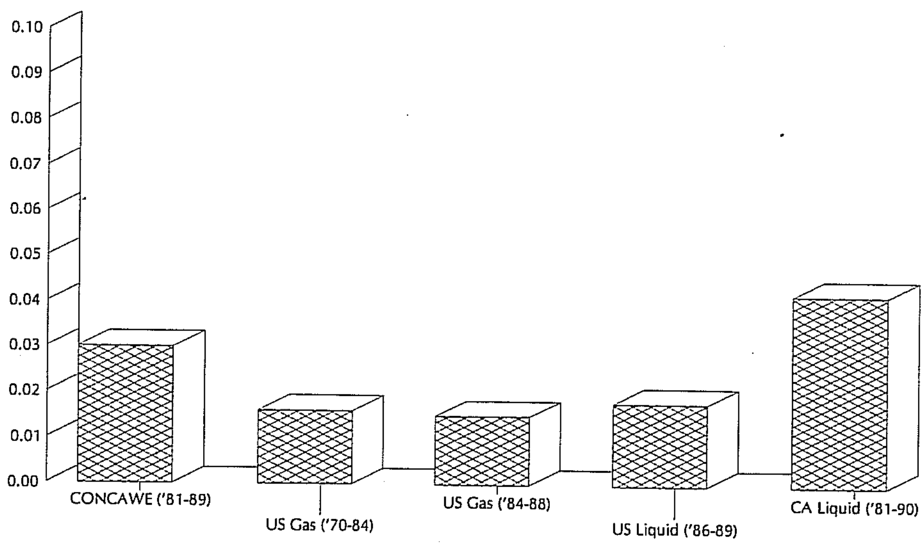


Note: The California data included all leaks and injuries, regardless of severity. Further, the California data was the only completely audited data sample represented. The resulting higher California incident rates do not necessarily indicate that California hazardous liquid pipelines pose a higher risk than those included in other studies. The reader should consult the report text for a more complete discussion.

Injury Rate Comparison
Injuries Per 1,000 Mile Years



Fatality Rate Comparison
Fatalities Per 1,000 Mile Years



Note: The California data included all leaks and injuries, regardless of severity. Further, the California data was the only completely audited data sample represented. The resulting higher California incident rates do not necessarily indicate that California hazardous liquid pipelines pose a higher risk than those included in other studies. The reader should consult the report text for a more complete discussion.

3.7 Uncorrected Pipeline Risks

Using the data developed in the prior subsections, one can estimate the incident rates for various pipeline events as follows:

Event	Incident Rate
any size leak	7.1 incidents per 1,000 mile years
property damage greater than $5,000	1.3 to 6.2 incidents per 1,000 mile years
property damage greater than $50,000	up to 4.4 incidents per 1,000 mile years
any injury	0.70 injuries per 1,000 mile years
injury requiring hospitalization	0.10 injuries per 1,000 mile years
fatality	0.02 to 0.04 fatalities per 1,000 mile years

These values may be useful when evaluating the risks associated with proposed pipeline projects. In most cases, these values would represent the upper limit of any increased risk for new projects. As we will see in subsequent sections of this report, new lines, with modern external coatings and adequate cathodic protection systems generally have much lower leak incident rates.

4.0 General Risk Levels

Before reviewing the specific study results, it is helpful to review a profile of the regulated hazardous liquid pipelines included in the study. This data is presented below:

Total Length of Regulated Pipelines Included in Study	7,800 Miles
Total Length of Regulated Pipeline within 500' of a Rail Included in Study	2,061 Miles (26.4%)
Total Length of Internal Inspection Piggable Pipeline Included in Study	4,495 Miles (57.6%)
Total Number of Line Sections Included in Study	552 Pipelines
Average Length of Each Section	14.1 Miles
Mean Year of Original Pipe Construction	1957
Mean Diameter of Pipe	12.3 Inches
Mean Diameter of Internal Inspection Piggable Pipe	14.3 Inches
Mean Normal Operating Temperature	97.9°F
Number of Leaks During Study Period	514 Leaks
Average Spill Size	408 Barrels
Median Spill Size	5 Barrels
Average Damage Per Incident (Uninflated)	$141,000
Median Damage Per Incident ($US 1983)	$7,200
Average Age Of Leak Pipe	40.8 Years
Average Diameter of Leak Pipe	10.2 Inches
Mean Normal Operating Temperature of Leak Pipe	109.7°F
Injuries During Study Period	49
Fatalities During Study Period	3

In the table above, the terms mean and average were used to differentiate between the methods used to calculate the values. *Average* values were determined by simple division. For example, the average spill size was determined by dividing the sum of each individual spill volume by the total number of spills. *Mean* values, on the other hand, were determined by *weighting* the individual parameters by pipe length and the number of years of service during the study period. For instance, the mean normal operating temperature was determined as follows:

$$T_{mean} = \Sigma \{T_i L_i Y_i + T_{(i+1)} L_{(i+1)} Y_{(i+1)} + \ldots\} \div \Sigma \{L_i Y_i + L_{(i+1)} Y_{(i+1)} + \ldots\}$$

where: T_{mean} = mean normal operating temperature
T_i = normal operating temperature for line $segment_i$
L_i = length of line $segment_i$
Y_i = number of years of line $segment_i$ operation during study period

We believe that this weighting method provides a much more meaningful representation of mean values for many parameters than simple division. It has been used where appropriate to determine the values shown in many of the tables which follow.

In general, the characteristics presented above for all pipelines do not differ dramatically from those characteristics for pipe where leaks occurred. Generally, pipelines where leaks occurred operated about 10°F hotter than the normal operating temperature for all pipe, and had a diameter roughly 2 inches smaller. The major difference was pipe age; the average age of all pipelines was about 31 years, while that of leak pipe was nearly 41 years.

In terms of distribution, approximately 26 percent of all pipe was within 500 feet of a rail line; as we shall see in a following subsection, a proportional percentage of the leak incidents occurred on these pipe segments. Nearly 60 percent of all pipelines were reported to be internally inspection piggable; 70 percent of the piggable lines were internally inspected during the ten year study period.

4.1 Overall Incident Causes

The overall incident rate for all pipelines included in this study was 7.12 incidents per 1,000 mile years. Table 4-1 presents the detailed data.

As indicated, the leading cause of hazardous liquid pipeline leak incidents from January 1981 through December 1990 was external corrosion, which caused 58.8 percent of all leaks. Another 2.7 percent were caused by internal corrosion. The volumes spilled as a result of both types of corrosion were nominal in size, relative to the spill size resulting from other causes (225 barrels on average for external corrosion leaks and 47 barrels for internal corrosion leaks, versus 723 barrels for other causes).

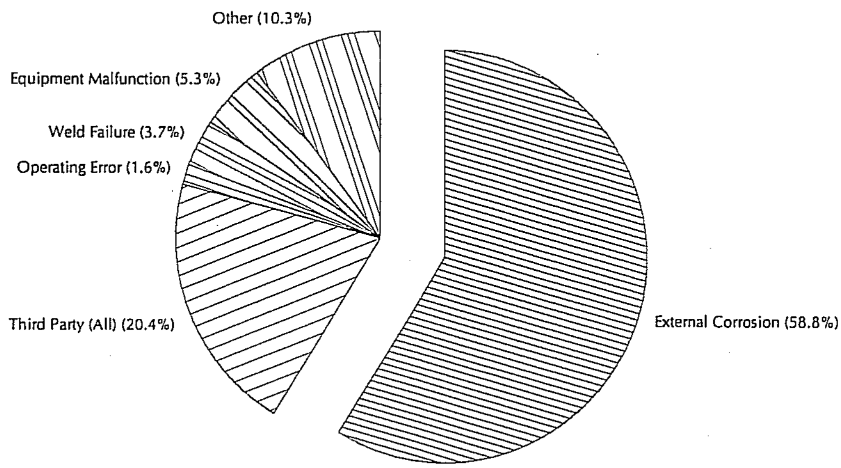
The second leading cause of all leaks was third-party damage. In our data, third party damage was subdivided into five categories:

- third party damage due to farm equipment,
- third party damage due to construction,
- third party damage due to train derailments,
- third party damage which caused coating damage resulting in subsequent external corrosion leaks, and
- third party damage due to other causes.

Table 4-1
Overall Incident Causes
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	No. of Incidents	Incident Rate	Percentage
External Corrosion	302	4.18	58.75%
Internal Corrosion	14	0.19	2.72%
3rd Party - Construction	64	0.89	12.45%
3rd Party Farm Equipment	18	0.25	3.50%
3rd Party - Train Derailment	2	0.03	0.39%
3rd Party - External Corrosion	7	0.10	1.36%
3rd Party - Other	14	0.19	2.72%
Human Operating Error	8	0.11	1.56%
Design Flaw	2	0.03	0.39%
Equipment Malfunction	27	0.37	5.25%
Maintenance	5	0.07	0.97%
Weld Failure	19	0.26	3.70%
Other	25	0.35	4.86%
Unknown	7	0.10	1.36%
Total	514	7.12	100.00%
Number of Mile Years	72,181		
Mean Year Pipe Constructed	1957		
Mean Operating Temperature (°F)	97.9		
Mean Diameter (inches)	12.3		
Average Spill Size (barrels)	408		
Average Damage ($US 1983)	141,477		

Incident Cause Distribution



All types of third party damage combined, were responsible for causing 20.4% of all leak incidents during our 10 year study period. Of these, construction activity was by far the major culprit, causing 12.5% of all leaks.

Spills resulting from third-party damage due to farm equipment were large, averaging over 1,600 barrels. Additionally, the largest quantity of fluid spilled occurred from the two leaks caused by train derailment; the two leaks in this category evidence a considerably large average spill size of 4,762 barrels of fluid.

A total of 46 leaks occurred due to equipment malfunction or weld failure. 5.3% of all leaks were caused by equipment malfunction while 3.7 percent of all leaks were attributable to weld failure. Spill sizes for these leaks averaged about 700 barrels of fluid.

The number of leaks that occurred because of human error, design flaw in pipe construction or poor maintenance procedures were nominal, together comprising less than three percent of all leaks. Despite the low frequency of leaks due to human operating error, the size of spill occurring as a result of these leaks is very large, averaging 3,102 barrels. This spill size is the second largest average spill size resulting from any cause. Leaks caused by poor maintenance, on the other hand, resulted in the lowest spill size, with an average of only 3.2 barrels.

4.2 Interstate versus Intrastate Pipelines

The data collected permited a categorization of pipeline units by interstate lines and intrastate lines. Approximately 28 percent of the regulated hazardous liquid pipelines within the state of California are interstate lines. A summary profile of these pipelines is shown below.

Description	Interstate Pipelines	Intrastate Pipelines
Total Number of Line Sections	71 Sections (12.9%)	480 Sections (87.1%)
Total Length of Pipelines	2,141 Miles (27.5%)	5,646 Miles (72.5%)
Total Length Within 500 feet of a Rail Line	819 Miles (38.3% of Interstate)	1,242 Miles (22.0% of Intrastate)
Total Length of Internal Inspection Piggable Pipe	1,970 Miles (92.0% of Interstate)	2,513 Miles (44.5% of Intrastate)
Average Length of Section	30.2 Miles	11.8 Miles
Mean Year of Original Pipe Construction	1966	1953
Mean Diameter of Pipe	16.7 Inches	10.7 Inches

Mean Diameter of Internal Inspection Piggable Pipe	17.6 Inches	12.1 Inches
Mean Normal Operating Temperature	77.3°F	106.1°F
Mean Normal Operating Pressure	1,033 psig	688 psig
Average Valve Spacing	9.92 Miles	6.58 Miles
Average Hydrostatic Test Interval	6.27 Years	4.51 Years
Number of Leaks During Study Period	48 Incidents	459 Incidents

Table 4-2 presents a comparison of the leak incident rates for interstate versus intrastate pipelines. Comparing these results we find that the leak incident rate for intrastate lines was significantly higher per 1,000 mile years than the incident rate for interstate pipelines: 8.45 in contrast to 2.69 leaks per 1000 mile years.

There are several possible explanations for the roughly three-fold difference between the interstate and intrastate pipeline incident rates. We believe that the following items had the greatest impact, as we will examine in later subsections of this report.

- The mean interstate pipeline was 13 years newer than the intrastate pipelines.

- The mean normal operating temperature was nearly ambient for interstate pipelines, almost 30°F less than for intrastate lines.

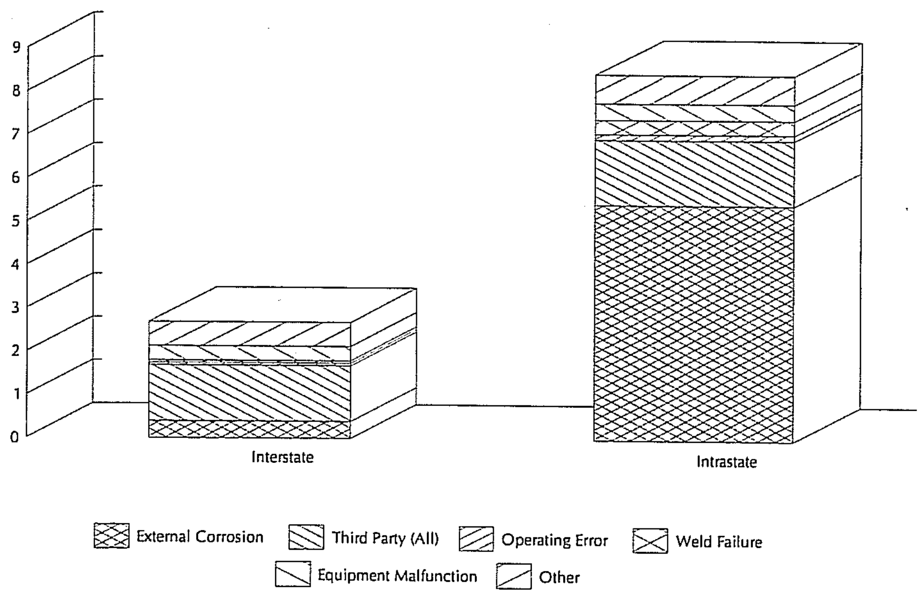
- The mean normal pipe diameter was almost 17" for interstate lines, over 50% greater than for intrastate lines.

As demonstrated in Table 4-2, the majority of the incident rate difference occurred in the incident rate for leaks caused by external corrosion. Also, the average spill size and average damage was considerable greater for the larger mean diameter interstate pipelines.

Table 4-2
Interstate versus Intrastate Pipelines
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Interstate		Intrastate	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	7	0.39	295	5.43
Internal Corrosion	0	0.00	14	0.26
3rd Party - Construction	14	0.78	50	0.92
3rd Party Farm Equipment	1	0.06	17	0.31
3rd Party - Train Derailment	2	0.11	0	0.00
3rd Party - External Corrosion	1	0.06	6	0.11
3rd Party - Other	5	0.28	9	0.17
Human Operating Error	1	0.06	7	0.13
Design Flaw	1	0.06	1	0.02
Equipment Malfunction	6	0.34	21	0.39
Maintenance	2	0.11	3	0.06
Weld Failure	1	0.06	18	0.33
Other	7	0.39	18	0.33
Total	48	2.69	459	8.45
Number of Mile Years	17,838		54,343	
Mean Year Pipe Constructed	1966		1953	
Mean Operating Temperature (°F)	77.3		106.1	
Mean Diameter (inches)	16.7		10.7	
Average Spill Size (barrels)	514		399	
Average Damage ($US 1983)	892,762		65,206	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



The average valve spacing was also worth noting. The average valve spacing on interstate pipelines was 9.92 miles, 51% greater than for intrastate lines. In addition, interstate lines had a mean pipe diameter which was 50% greater than for intrastate lines. If we assume an average wall thickness of 0.25" for all lines, the mean fluid contents per mile for interstate and intrastate pipelines can be calculated to be 1,344 and 535 barrels per mile respectively. After correcting for the difference in mean pipe diameter and average valve spacing, one would expect the average spill volume for interstate lines to be 3.8 times that for intrastate lines, assuming valve spacing had a direct relationship with spill volume. However, the average spill volume for interstate lines was only 29% greater than for intrastate lines, 351% less than one may have expected. Obviously, other factors significantly affect spill volumes, as we shall review in a later section.

4.3 Common Carrier versus Non-Common Carrier Lines

Analyses similar to those for interstate versus intrastate pipeline have been performed for common carrier (those transporting freight for hire) versus non-common carrier lines. Approximately 25 percent of the regulated hazardous liquid pipelines within the State of California were common carrier lines. A summary profile of these pipelines has been presented below.

Description	Common Carrier Pipelines	Non-Common Carrier Pipelines
Total Number of Line Sections	135 Sections (24.5%)	416 Sections (75.5%)
Total Length of Line Sections	3,602 Miles (46.3%)	4,186 Miles (53.7%)
Total Length Within 500 feet of a Rail Line	1,452 Miles (40.3% of Common Carrier Pipelines)	609 Miles (14.5% of Non-Common Carrier Pipelines)
Total Length of Internal Inspection Piggable Pipe	2,831 Miles (78.6% of Common Carrier Pipelines)	1,652 Miles (39.5% of Non-Common Carrier Pipelines)
Average Length of Section	26.7 Miles	10.1 Miles
Mean Year of Original Pipe Construction	1964	1951
Mean Diameter of Pipe	13.9 Inches	11.0 Inches
Mean Diameter of Internal Inspection Piggable Pipe	15.2 Inches	13.1 Inches
Mean Normal Operating Temperature	81.1°F	112.3°F
Mean Normal Operating Pressure	933 psig	664 psig

Average Valve Spacing	10.14 Miles	5.32 Miles
Average Hydrostatic Test Interval	5.88 Years	4.38 Years
Number of Leaks During Study Period	104	403

Tables 4-3 presents a comparison of the leak incident rates for common carrier versus non-common carrier pipelines. Comparing these results we find that the leak incident rate for non-common carrier lines was roughly three times greater than for common carrier pipelines: 9.88 in contrast to 3.31 incidents per 1,000 mile years. Once again, nearly all of the incident rate difference occurred in the rate for leaks caused by external corrosion.

The differences between these line sections were very similar to those for interstate and intrastate pipelines discussed in the prior subsection. We believe that the following items had the greatest impact on the differences between common carrier and non-common carrier leak incident rates. (Each of these parameters will be examined individually in subsequent subsections of this report.)

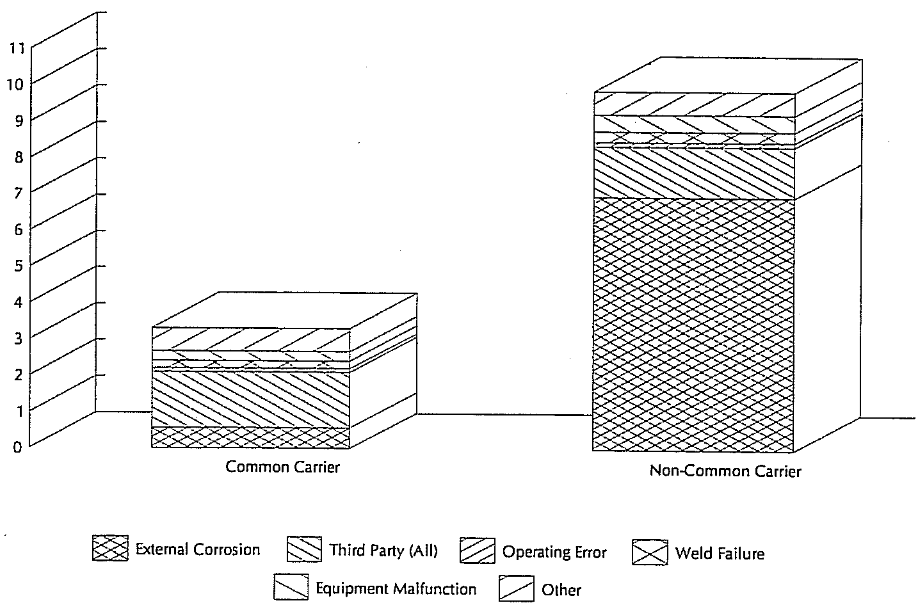
- The mean common carrier line was 13 years newer than the non-common carrier pipeline.
- The mean normal operating temperature was 31°F less than for common carrier lines than it is for non-common carrier pipelines.
- The mean normal pipe diameter was almost 14" for common carrier lines, over 25% greater than non-common carrier lines.

The average valve spacing differences were also very similar to those for interstate and intrastate pipelines. The average valve spacing on common carrier pipelines was 10.14 miles, 91% greater than for non-common carrier lines. In addition, common carrier lines had a mean pipe diameter which was 26% greater than for non-common carrier lines. If we assume an average wall thickness of 0.25" for all lines, the mean fluid contents per mile for common carrier and non-common carrier pipelines can be calculated to be 925 and 567 barrels per mile respectively. After correcting for the difference in mean pipe diameter and average valve spacing, one would expect the average spill volume for common carrier lines to be 2.5 times that for non-common carrier lines, assuming valve spacing had a direct relationship with spill volume. However, the average spill volume for common carrier lines was only 25% greater than for non-common carrier lines, 225% less than one may have expected.

Table 4-3
Common Carrier versus Non-Common Carrier Pipelines Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Common Carrier		Non-Common Carrier	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	18	0.57	284	6.96
Internal Corrosion	3	0.10	11	0.27
3rd Party - Construction	30	0.96	34	0.83
3rd Party Farm Equipment	6	0.19	12	0.29
3rd Party - Train Derailment	2	0.06	0	0.00
3rd Party - External Corrosion	1	0.03	6	0.15
3rd Party - Other	9	0.29	5	0.12
Human Operating Error	3	0.10	5	0.12
Design Flaw	2	0.06	0	0.00
Equipment Malfunction	8	0.25	19	0.47
Maintenance	4	0.13	1	0.02
Weld Failure	7	0.22	12	0.29
Other	11	0.35	14	0.34
Total	104	3.31	403	9.88
Number of Mile Years	31,385		40,796	
Mean Year Pipe Constructed	1964		1951	
Mean Operating Temperature (°F)	81.1		112.3	
Mean Diameter (inches)	13.9		11.0	
Average Spill Size (barrels)	484		387	
Average Damage ($US 1983)	396,163		61,050	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



4.4 Incident Rates By Pipeline Contents

The incident rates differed by the type of fluid transported. Table 4-4 details incident rates by cause and pipeline contents. The incident rate for crude oil pipelines (comprising 43.4% of the total mile years of operation during the study period) was 9.89 incidents per 1,000 mile years. This was more than double the rate for product pipelines which represented 50.4% of the mile years of operation during the study period. (Product pipelines included those which transport gasolines, diesel, jet fuel, etc.)

The vast majority of this difference was external corrosion. A regression analysis was performed to review the effect of pipe contents, specifically crude oil, on the probability of a leak. The analysis included the following variables, as well as a dummy indicator for whether or not the line carried crude oil:

- total length of pipeline section,
- year of pipe construction,
- normal operating temperature,
- normal operating pressure, and
- normal operating flow rate.

We found that by controlling for factors such as year of construction, operating temperature and other pertinent variables, the relationship disappeared between crude oil transportation and the probability of a leak, for those leaks caused by factors other than external corrosion. *Crude oil, however, was a statistically significant determinant that strongly raised the probability of a leak occurring because of external corrosion.* As we will examine in a later subsection, this was largely a result of operating temperature. As indicated in Table 4-4, the mean operating temperature for crude oil lines was 109°F, versus 86°F for product lines.

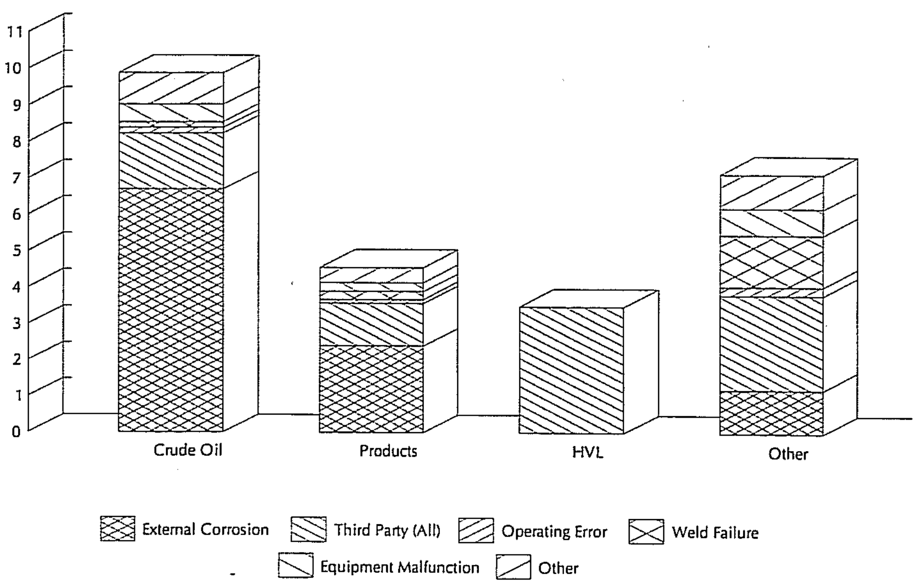
It was also interesting to note that all of the injuries and fatalities occurred on product pipelines. In addition, the average damage per incident was $363,000 for product lines (constant $US 1983), almost four times that for crude oil pipelines. Based on the pipe diameter differences between crude and product pipelines, one would expect average crude oil spills to be twice the size of those for product lines, all other things being equal. However, the data indicates that the average crude oil spill volume was only 42% greater than for product lines. Fluid viscosity may help explain this discrepancy. The more viscous crude oil would take much longer to drain from a severed line than petroleum products, which would tend to reduce crude oil spill volumes.

The number of leaks and total mile years of operation during the study period for highly volatile liquid (HVL) and "other" lines was relatively small. The reader should be cautioned against making anything but very general conclusions using the results of this small data base.

Table 4-4
Incidents By Pipeline Contents
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Crude Oil		Products		HVL		Other	
	Number	Rate	Number	Rate	Number	Rate	Number	Rate
External Corrosion	210	6.70	87	2.39	0	0.00	5	1.19
Internal Corrosion	10	0.32	1	0.03	0	0.00	3	0.72
3rd Party - Construction	28	0.89	28	0.77	1	3.48	7	1.67
3rd Party Farm Equipment	14	0.45	1	0.03	0	0.00	3	0.72
3rd Party - Train Derailment	0	0.00	2	0.05	0	0.00	0	0.00
3rd Party - External Corrosion	2	0.06	4	0.11	0	0.00	1	0.24
3rd Party - Other	4	0.13	8	0.22	0	0.00	0	0.00
Human Operating Error	5	0.16	4	0.11	0	0.00	1	0.24
Design Flaw	2	0.06	0	0.00	0	0.00	0	0.00
Equipment Malfunction	15	0.48	9	0.25	0	0.00	3	0.72
Maintenance	2	0.06	2	0.05	0	0.00	1	0.24
Weld Failure	5	0.16	8	0.22	0	0.00	6	1:43
Other	13	0.41	12	0.33	0	0.00	0	0.00
Total	310	9.89	166	4.55	1	3.48	30	7.15
Number of Mile Years	31,350		36,473		287		4,193	
Percentage of Total Mile Years	43.4%		50.4%		0.4%		5.8%	
Injuries Per 1,000 Mile Years	0	0.00000	49	1.34345	0	0.00000	0	0.00000
Fatalities Per 1,000 Mile Years	0	0.00000	3	0.08225	0	0.00000	0	0.00000
Mean Year Pipe Constructed	1956		1960		1960		1944	
Mean Operating Temperature (°F)	109		86		73		120	
Mean Diameter (inches)	14.6		10.4		6.5		12.2	
Average Spill Size (barrels)	475		335		30		106	
Average Damage ($US 1983)	96,475		363,073		0		20,368	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



4.5 Incident Rates By Study Year

Varying leak incident rates were observed during the ten year study period. Table 4-5 shows the incident rate break-down for each year during the survey period by cause.

The results demonstrate a slight decline over the ten year period: during the first five years the average incident rate was 8.5; during the latter half the average incident rate was 6.9 leaks per 1,000 mile years. An ordinary least squares line of best fit was determined to evaluate the statistical relevance of this overall leak data by year. It showed that the overall incident rate decreased 0.52 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* for this regression was 0.39. (*R squared* values range from zero to one. They can be interpreted as the proportion of the variation in a given sample which can be explained by the resulting linear equation; they are a comparison of the estimated systematic model with the mean of the observed values.)

A similar regression was performed for external corrosion leaks only during the ten year study period. It indicated that the incident rate for external corrosion leaks was decreasing at the rate of 0.21 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.24.

The decreasing trend in incident rates is especially noteworthy considering the fact that all leak data was gathered at the end of the study period. With the increasing trend towards total leak reporting and recording, one would assume that the more recent data collected from a pipeline operator may be more complete than data regarding leaks which occurred several years ago. This would tend to result in relatively lower incident rates for early study years and a corresponding increasing incident rate trend. However, as discussed earlier, the data indicated a rather significant *decreasing* incident rate trend. This indicates two things: first, it indicates that the data gathered must be relatively complete during the earlier years of the study; secondly, it indicates that if any incomplete record keeping did occur during the early years of the study period, the actual rate of decreasing incident rates was higher than indicated by the regressions.

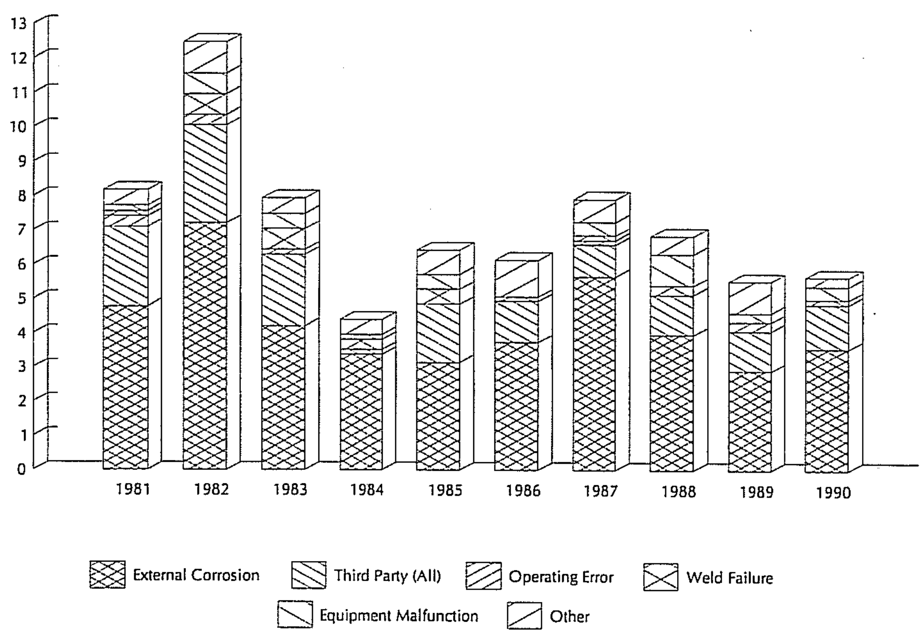
A third regression was performed for leaks caused by all causes except external corrosion during the ten year study period. It indicated that the incident rate for these leaks was decreasing at the rate of 0.19 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.26.

The average spill volumes varied widely during the ten year study period. An ordinary least squares line of best fit was determined to analyze any trend in this data. It indicated a 33.6 barrel per year reduction in average spill size, with an *R squared* of only 0.16.

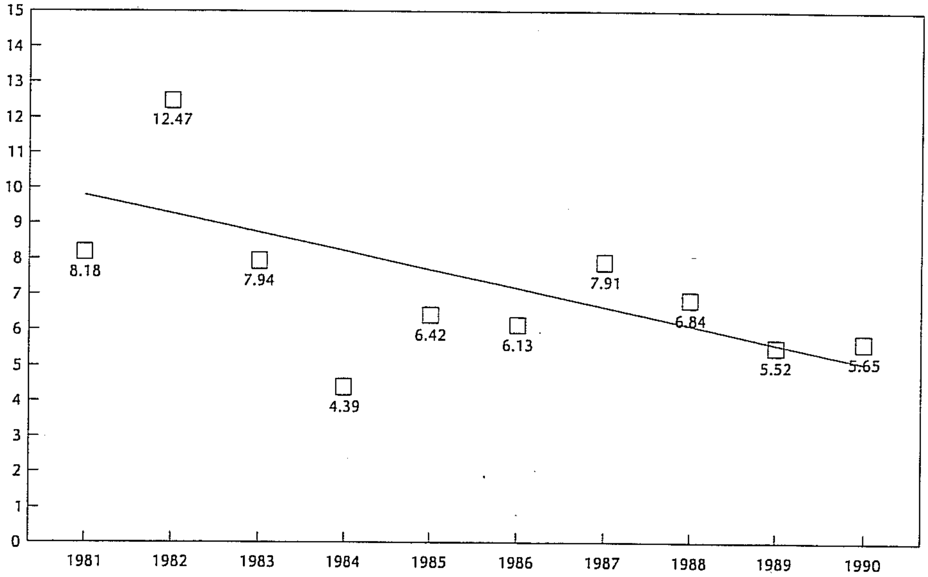
Table 4-5
Incident Rates By Year Of Study
(Incidents Per 1,000 Mile Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
External Corrosion	4.78	7.21	4.19	3.36	3.14	3.73	5.67	3.95	2.89	3.55
Internal Corrosion	0.00	0.45	0.30	0.15	0.14	0.40	0.53	0.00	0.00	0.00
3rd Party - Construction	1.08	2.40	0.60	0.15	1.43	0.67	0.66	0.79	0.79	0.53
3rd Party - Farm Equipment	1.08	0.15	0.90	0.00	0.00	0.13	0.13	0.13	0.13	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.13	0.00
3rd Party - External Corrosion	0.00	0.00	0.00	0.00	0.14	0.00	0.13	0.00	0.00	0.66
3rd Party - Other	0.15	0.30	0.60	0.00	0.14	0.40	0.00	0.13	0.13	0.13
Human Operating Error	0.31	0.30	0.15	0.00	0.00	0.00	0.13	0.00	0.26	0.00
Design Flaw	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.13
Equipment Malfunction	0.15	0.60	0.45	0.15	0.43	0.00	0.40	0.92	0.26	0.39
Maintenance	0.00	0.00	0.00	0.00	0.29	0.00	0.00	0.00	0.39	0.00
Weld Failure	0.15	0.60	0.60	0.29	0.43	0.13	0.13	0.26	0.00	0.13
Other	0.46	0.45	0.15	0.29	0.29	0.67	0.13	0.39	0.53	0.13
Total	8.18	12.47	7.94	4.39	6.42	6.13	7.91	6.84	5.52	5.65
Number of Mile Years	6,482	6,658	6,675	6,835	7,005	7,501	7,587	7,600	7,609	7,610
Mean Year Pipe Constructed	1952	1953	1953	1954	1954	1956	1957	1957	1957	1957
Mean Operating Temperature (°F)	97.0	97.4	97.4	96.8	98.4	97.9	98.0	97.9	98.0	98.0
Mean Diameter (inches)	10.8	10.9	10.9	10.9	11.1	12.3	12.3	12.4	12.4	12.4
Average Spill Size (barrels)	285.0	514.7	889.3	83.6	562.9	609.4	266.6	136.2	377.5	127.4
Average Damage ($1,000 US 1983)	11.0	26.5	92.8	25.6	94.4	171.9	21.4	60.7	651.2	141.4

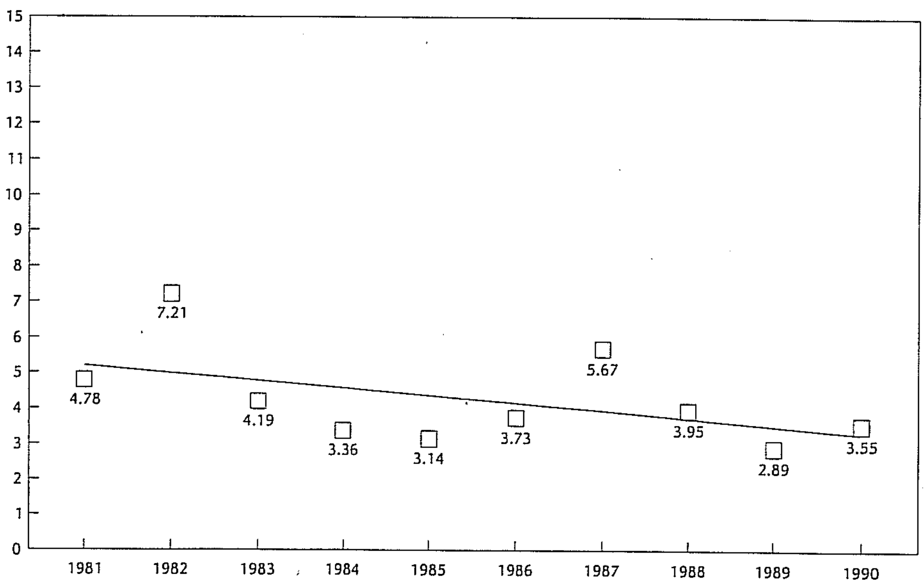
Incident Rates By Year of Study
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Year of Study
Incidents Per 1,000 Mile Years

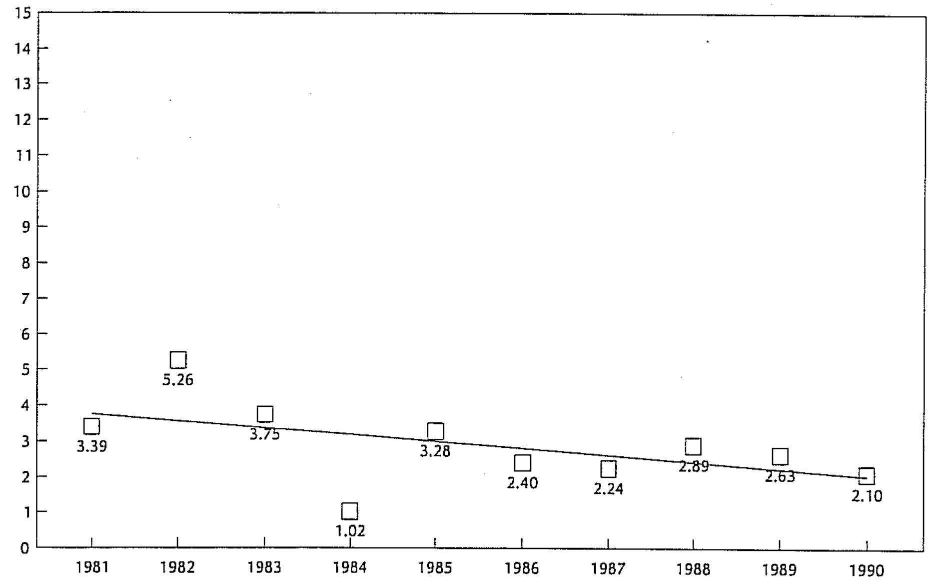


Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Decade of Construction
Incidents Per 1,000 Mile Years

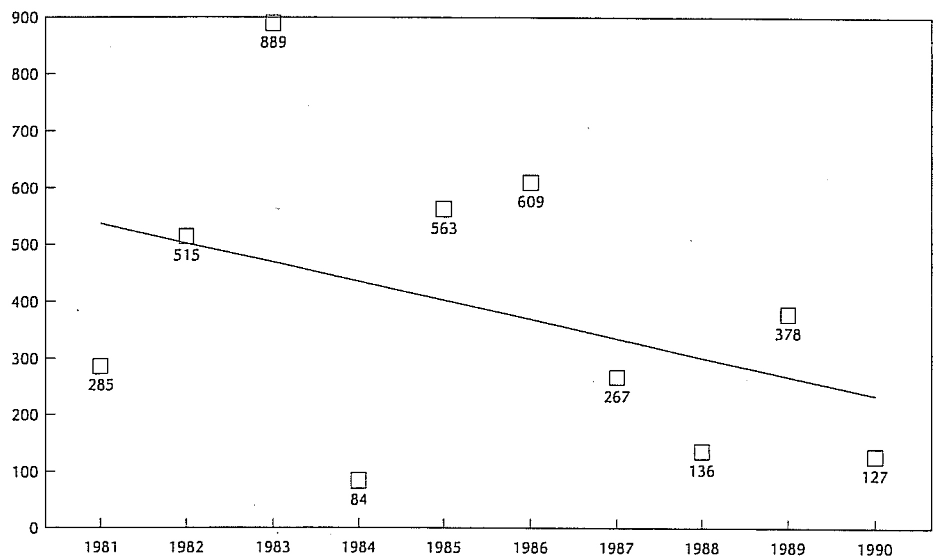


Ordinary Least Squares Line of Best Fit
Incident Rates For Other Causes By Year of Study
Excludes All External Corrosion Incidents

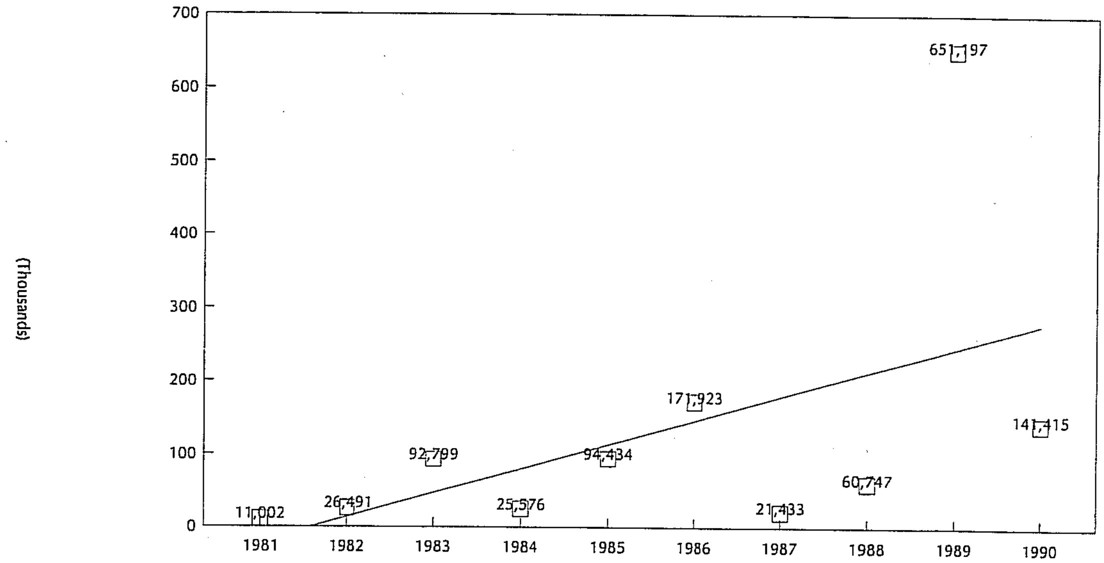
Incidents Per 1,000 Mile Years



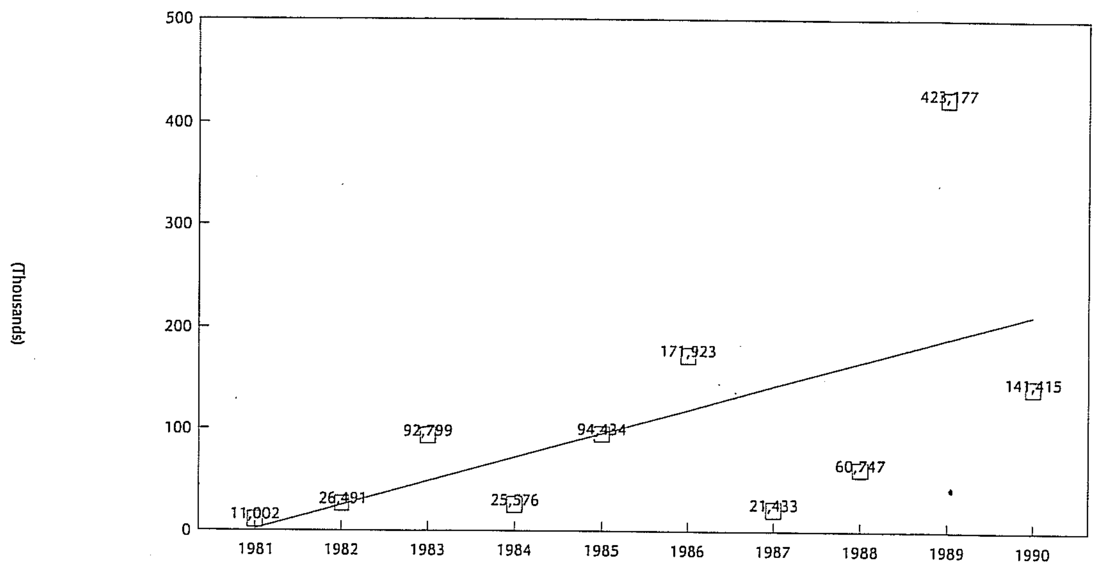
Ordinary Least Squares Line of Best Fit
Average Annual Spill Size (Barrels)



Ordinary Least Squares Line of Best Fit
Average Cost of Damage
$US 1983 - 1,000's



Ordinary Least Squares Line of Best Fit
Average Cost of Damage - Excluding 1989 Train Derailment Incident
$US 1983 - 1,000's



Finally, ordinary least squares lines of best fit were determined for the average cost of damage per incident during the ten year study period. Prior to running the regressions, all cost data was normalized to constant 1983 US dollars. Using all incidents during the study period yielded a $33,040 ($US 1983) per year increase in average spill cost, with an *R squared* of 0.27. After deleting the 1989 San Bernardino train derailment, the regression indicated a $23,366 ($US 1983) per year increase in average spill cost, with an *R squared* of 0.33.

4.6 Railroad Effect

As discussed earlier, one of the major inspirations behind this research effort was the 1989 San Bernardino train derailment. Our analyses directly addressed the relationship between train derailments and pipeline leaks. Of all of the hazardous liquid pipelines included in the study, 2,061 miles (26.4%) were located within 500 feet of a rail line; the remaining 5,742 miles (73.6%) were further away from any rail lines.

The data clearly evidence a lack of correlation between proximity to a rail line and any increased incidence of pipeline leaks. As depicted in Table 4-6, the incident rate for leaks occurring on all hazardous liquid pipelines within 500 feet of a rail line was actually 0.17 incidents per 1,000 mile years less than the rate observed for other pipe. Specifically, the overall incident rate was 6.79 incidents per 1,000 mile years for pipe within 500 feet of a rail line, versus 6.96 incidents per 1,000 mile years for other pipe.

As mentioned in Section 2.10 earlier, the length of pipeline within 500' of a rail line was resolved to within 1.7% by comparing EDM Services' mapped information with that provided by the pipeline operators. As a result, all data presented in this section regarding incident rates associated with rail lines has an inherent 1.7% uncertainty.

The two pipeline leaks which were caused by train derailments during the study period resulted in a leak incident rate for this cause of only 0.03 incidents per 1,000 mile years. It should also be noted that both of these leaks were actually caused by damage from clean up equipment, not the derailment itself.

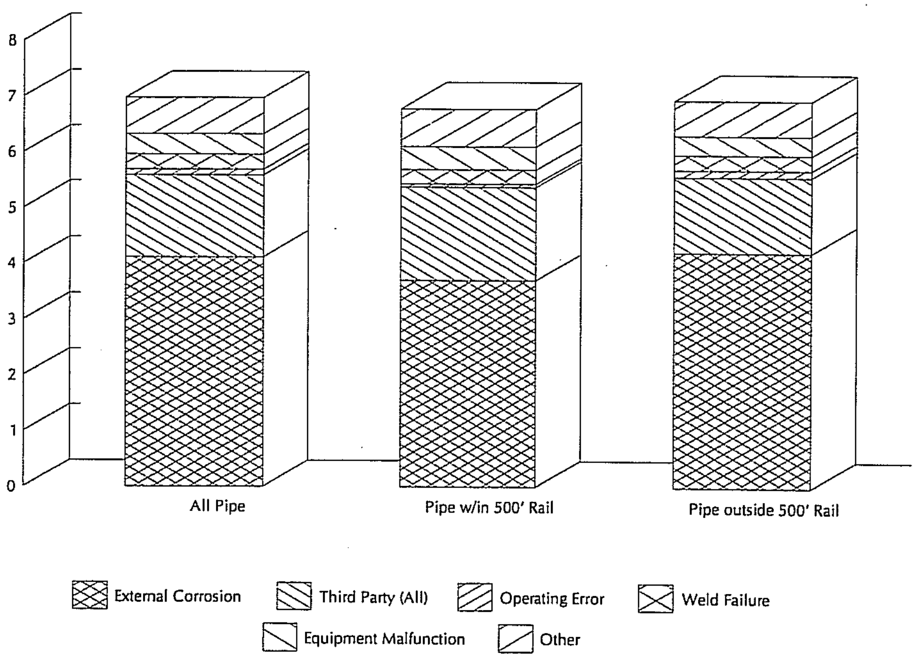
This high level of safety is remarkable, since 1,990 train derailments were reported to the Public Utilities Commission during the study period. Although we do not know how many of these occurred near regulated hazardous liquid pipelines, one can conclude that the likelihood of a derailment resulting in pipeline rupture is extremely remote. Further, the frequency of train derailment caused leak incidents is the lowest of any cause included in the study.

The average spill size of leaks occurring within 500 feet of a rail line is roughly one third the average spill size for other lines. This is especially noteworthy considering the relatively large derailment caused spills.

Table 4-6
Railroad Effect
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	All Pipe		Pipe w/in 500' Rail		Pipe outside 500' Rail	
	Total No.	Rate	Number	Rate	Number	Rate
External Corrosion	298	4.12	71	3.71	227	4.22
Internal Corrosion	14	0.19	3	0.16	11	0.20
3rd Party - Construction	64	0.89	21	1.10	43	0.80
3rd Party Farm Equipment	18	0.25	0	0.00	18	0.33
3rd Party - Train Derailment	2	0.03	2	0.10	0	0.00
3rd Party - External Corrosion	7	0.10	3	0.16	4	0.07
3rd Party - Other	14	0.19	6	0.31	8	0.15
Human Operating Error	8	0.11	1	0.05	7	0.13
Design Flaw	2	0.03	0	0.00	2	0.04
Equipment Malfunction	27	0.37	8	0.42	19	0.35
Maintenance	5	0.07	2	0.10	3	0.06
Weld Failure	19	0.26	5	0.26	14	0.26
Other	26	0.36	8	0.42	18	0.33
Total	504	6.97	130	6.79	374	6.96
Number of Mile Years	72,303		19,150		53,771	
Average Spill Size (barrels)			288		452	
Average Damage ($US 1983)			363,732		92,689	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



The average damage was much larger for leak incidents near rail lines: $363,732 ($US 1983) per incident versus $92,689 for other incidents.

4.7 Standard Metropolitan Statistical Areas (SMSA's)

One of the objectives of our study was to determine whether or not pipe within standard metropolitan statistical areas (SMSA) had a significantly different leak incident rate than pipelines outside SMSA's. For this purpose a substantial amount of time was spent by EDM office personnel explicitly mapping the locations of all regulated hazardous liquid pipelines within the state. This was done by measuring the length of line off of the Thomas Guide map book overlays as described earlier in Section 2.4. As a data verification check, the total length of line measured from the Thomas Guide overlays was compared to the total pipeline lengths furnished from the pipeline operators. These two figures were resolved to within 0.92 miles, or 0.01% of each other. (The actual length of pipe within each County will be presented later in Table 5-2A, along with other data.)

Table 4-7 presents the results of our work. Nearly 74% (5,827 miles) of California's hazardous liquid pipe was within SMSA county lines, while the remaining 2,084 miles of pipe were outside SMSA's. The leak rates observed within SMSA's were over three times higher than those observed outside of SMSA's, 7.84 versus 2.49 incidents per 1,000 mile years.

One hypothesis for the higher incident rate for pipelines within SMSA's was that since SMSA's contained zones which were densely populated, heavy third party activity could result in a higher frequency of accidental pipeline rupture. Indeed, the combined incident rate for third party activity was nearly twice as high in SMSA's than it was outside SMSA's, 1.51 versus 0.81 incidents per 1,000 mile years.

However, the vast majority of the difference between SMSA and non-SMSA leak incident rates resulted from external corrosion. Within SMSA's, we observed a rate of 4.86 incidents per 1,000 mile years; outside SMSA's the external corrosion incident rate was only 1.01 incidents per 1,000 mile years, roughly one-fifth the value for pipe within SMSA's. Although the data collected did not allow us to specifically analyze the reasons for this difference, there are several possible explanations:

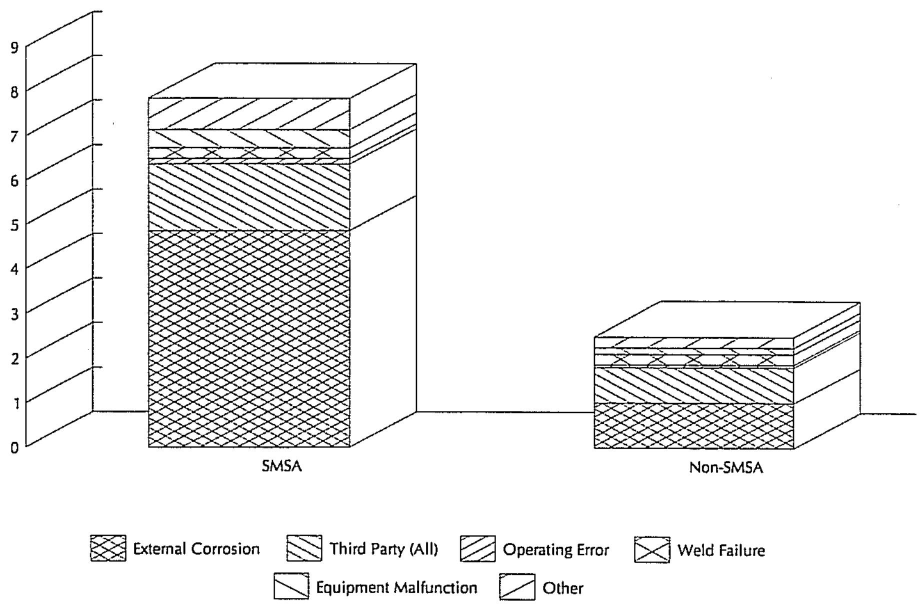
- Pipelines in densely populated areas are likely to be subjected to cathodic protection system interference from other nearby substructures.

- Pipelines buried beneath paved streets are more difficult or impossible to access for specialized cathodic protection surveys (e.g. close interval surveys) to identify locations with marginal or inadequate protection.

Table 4-7
Standard Metropolitan Statistical Areas (SMSA)
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	SMSA		Non-SMSA	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	283	4.86	21	1.01
Internal Corrosion	14	0.24	0	0.00
3rd Party - Construction	56	0.96	9	0.43
3rd Party Farm Equipment	14	0.24	3	0.14
3rd Party - Train Derailment	0	0.00	2	0.10
3rd Party - External Corrosion	7	0.12	0	0.00
3rd Party - Other	11	0.19	3	0.14
Human Operating Error	7	0.12	1	0.05
Design Flaw	1	0.02	1	0.05
Equipment Malfunction	24	0.41	3	0.14
Maintenance	5	0.09	0	0.00
Weld Failure	14	0.24	5	0.24
Other	21	0.36	4	0.19
Total	457	7.84	52	2.49
Number of Mile Years	58,277		20,844	
Average Spill Size (barrels)	331		1,049	
Average Damage ($US 1983)	96,807		395,326	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



- The cost of replacing pipe sections in urban areas is generally much higher than it is for rural areas, especially for pipe within roadways. This relatively high replacement cost may cause many operators to defer replacements in these areas.

- It is often extremely difficult, and sometimes nearly impossible, to secure the permits required to construct new lines or replace pipelines with high leak-history in urban areas, even though this work would reduce the risk to the public.

4.8 Decade of Construction Effects

Pipe age had a definite effect on the leak incident rates. Table 4-8 shows the variation in leak incident rates by decade of pipe construction. As indicated, pipe construction before 1940 (1926 mean year of construction) had a leak incident rate nearly twenty times that of pipe constructed in the 1980's. An ordinary least squares line of best fit was determined to evaluate the statistical relevance of the overall leak data by year of pipe construction. It indicated that the overall leak incident rate decreased 0.286 incidents per year per 1,000 mile years. The resulting *R squared* for this regression was 0.82. A second regression was performed which excluded all pipe installed prior to 1940. This regression indicated an overall leak incident rate reduction of 0.147 incidents per year per 1,000 mile years, with an *R squared* of 0.86.

Once again, we found that the vast majority of the difference in leak incident rates occurred because of variations in external corrosion rates. Some of the reasons for this variation may have included:

- The extent of external corrosion is generally considered a function of time. In general, the more time a given portion of pipe is allowed to corrode, the more likely it will be to develop a leak.

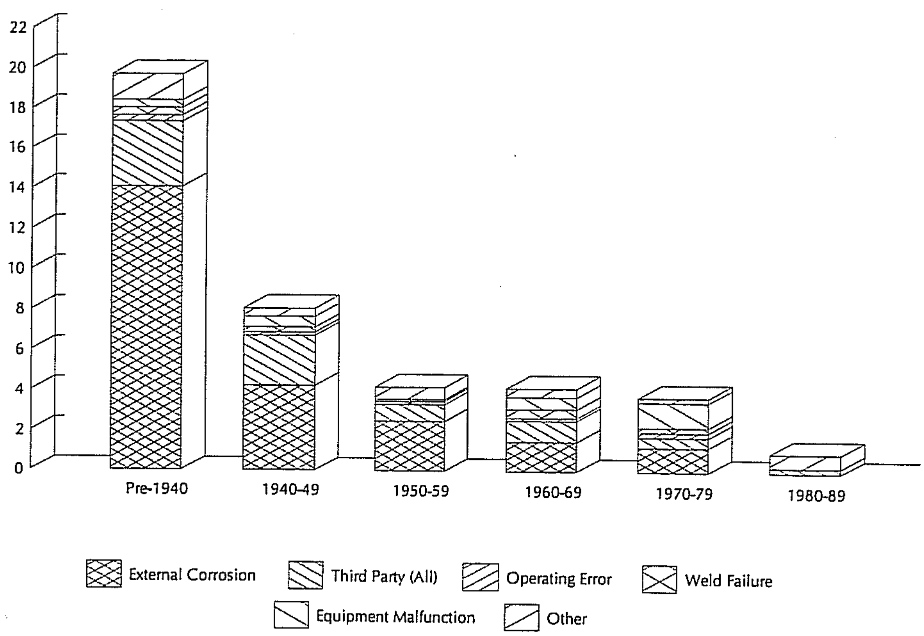
- Most believe that modern coatings are generally more effective than older coatings, especially those installed before the 1940's. The older pipe is likely to experience a higher external corrosion incident rate as a result.

- External corrosion rates are generally higher at elevated temperatures. Since the pre-1940 pipe had a mean operating temperature of 125°F, higher than the mean operating temperature for pipe constructed during any other period, one would anticipate a higher external corrosion rate.

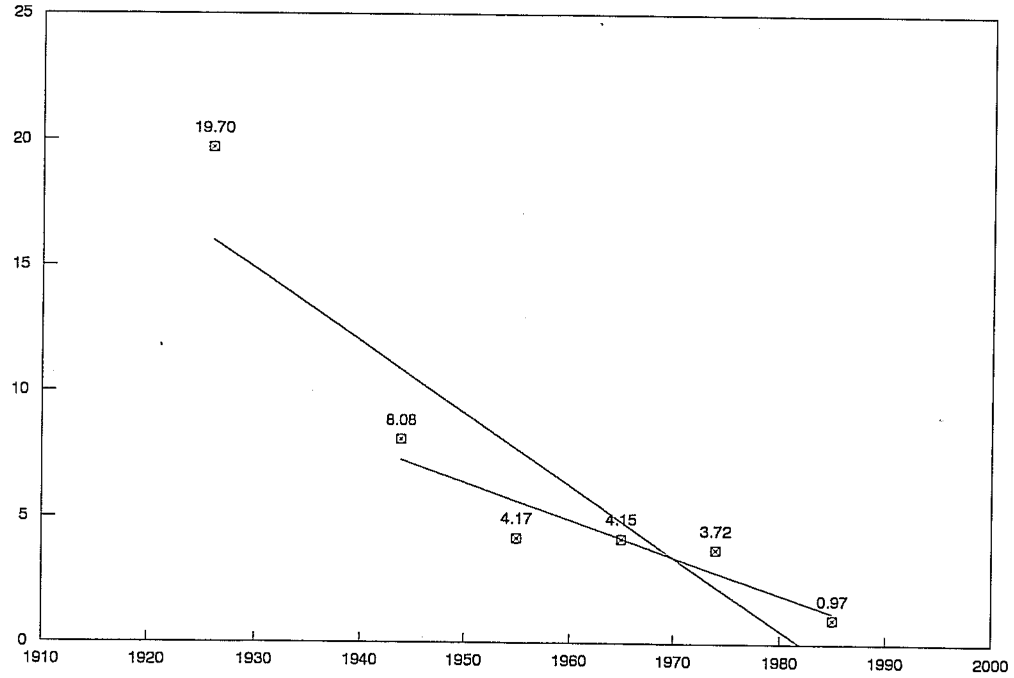
Table 4-8
Incident Rates By Decade of Construction
(Incidents Per 1,000 Mile Years)

Cause of Incident	Pre-1940	1940-49	1950-59	1960-69	1970-79	1980-89
External Corrosion	14.12	4.24	2.47	1.47	1.24	0.00
Internal Corrosion	0.38	0.27	0.10	0.16	0.00	0.28
3rd Party - Construction	1.96	1.06	0.68	0.66	0.25	0.28
3rd Party - Farm Equipment	0.53	1.33	0.05	0.00	0.00	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.05	0.25	0.00
3rd Party - External Corrosion	0.45	0.00	0.10	0.33	0.00	0.00
3rd Party - Other	0.30	0.13	0.05	0.05	0.00	0.00
Human Operating Error	0.30	0.13	0.00	0.11	0.25	0.00
Design Flaw	0.08	0.00	0.00	0.00	0.00	0.14
Equipment Malfunction	0.38	0.53	0.10	0.60	1.24	0.00
Maintenance	0.00	0.00	0.24	0.00	0.00	0.00
Weld Failure	0.38	0.27	0.15	0.44	0.25	0.00
Other	0.83	0.13	0.24	0.27	0.25	0.28
Total	19.70	8.08	4.17	4.15	3.72	0.97
Number of Mile Years	13,247	7,546	20,612	18,311	4,030	7,252
Average Year Pipe Constructed	1926	1944	1955	1965	1974	1985
Average Operating Temperature (°F)	125.2	79.7	89.4	91.4	99.8	104.1
Average Diameter (inches)	8.58	11.11	11.82	11.27	13.79	19.55
Average Spill Size (barrels)	162	492	246	1,306	53	789
Average Damage ($US 1983)	31,273	119,603	169,741	496,156	85,778	164,314

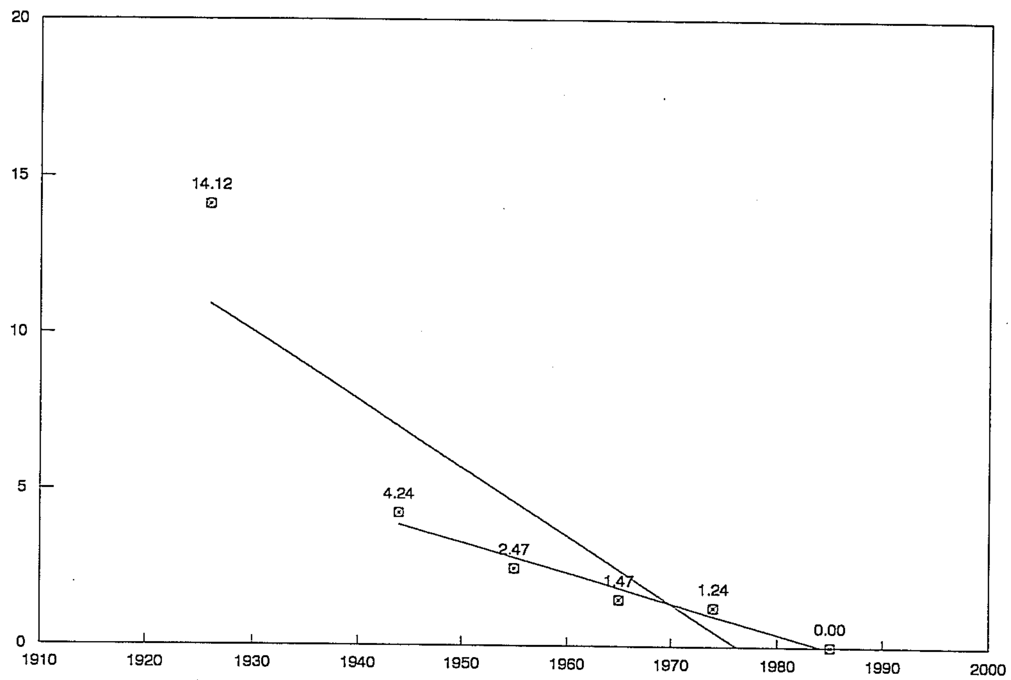
Incident Rates By Decade of Construction
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Year of Pipe Construction
Incidents Per 1,000 Mile Years

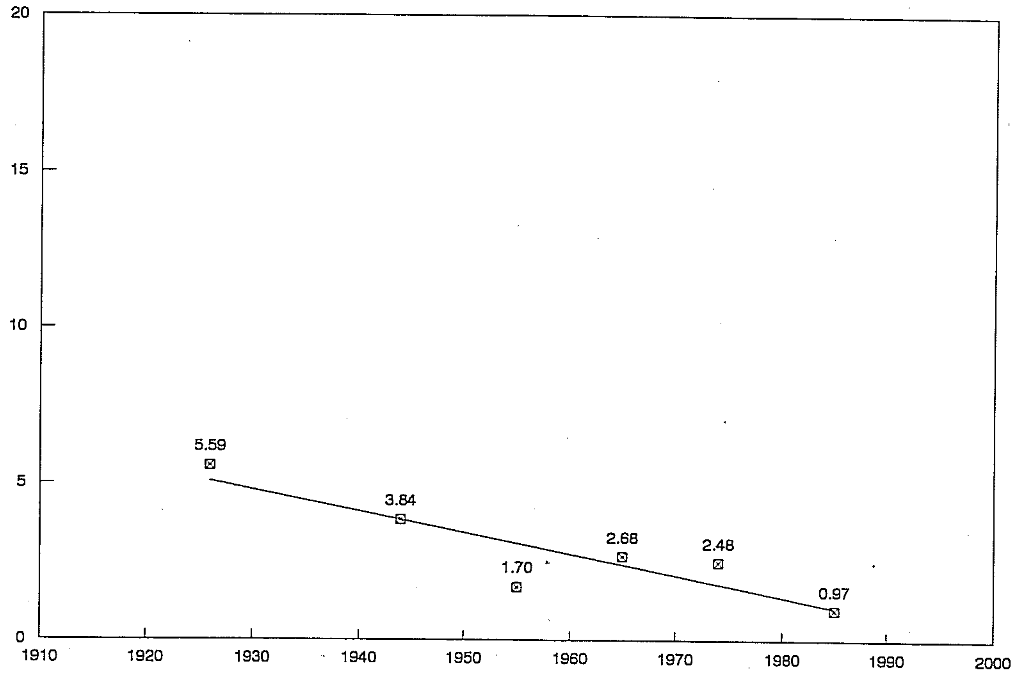


Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Year of Pipe Construction
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Incident Rates For Other Causes By Year of Pipe Construction
Excludes All External Corrosion Incidents

Incidents Per 1,000 Mile Years



- Prior to the 1950's, it was common to install pipelines with little or no cathodic protection. For the most part, these older systems have either had new systems installed, or their older systems upgraded, to be consistent with present day practices. However, they often operated for several years with inadequate or no cathodic protection. The corrosion which occurred during these early years likely increased the resulting external corrosion leak incident rate.

An ordinary least squares line of best fit was determined for the external corrosion data only. Using all data, it indicated that the external corrosion rate declined by 0.217 incidents per year per 1,000 mile years, with an *R squared* of 0.79. A similar regression was performed excluding all pipe constructed prior to 1940. This regression indicated an external corrosion rate reduction of 0.097 incidents per year per 1,000 mile years, with an *R squared* of 0.95. However, it should be noted that both of these regressions resulted in a least squares line fit which would indicate a negative incident rate during the study period, which is impossible. However, the point should be made that there is a strong statistical relationship between pipe age and rate of external corrosion; the newer the pipe, the lower the external corrosion incident rate.

A third ordinary least squares line of best fit was prepared for leaks caused by all causes except external corrosion. It indicated that the incident rate for these leaks decreased at the rate of 0.069 incidents per year per 1,000 mile years. The resulting *R squared* was 0.80.

It is interesting to note that the leak incident rate for pipe constructed during the 1950's, 60's and 70's was relatively constant, at about 4 incidents per 1,000 mile years. However, for pipe installed during the 1980's, the incident rate dropped to roughly 1 incident per 1,000 mile years. At the present, we believe that it is too soon to conclude whether or not this was simply a result of the limited time in service, or the result of any changes in pipeline construction or other practices. It will be interesting to note during future studies whether or not this difference continues.

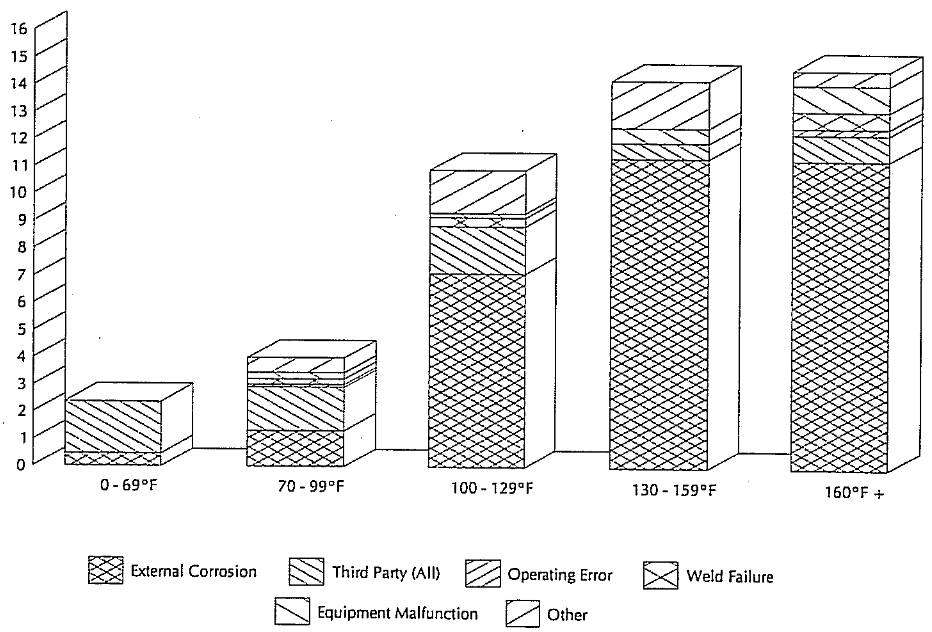
4.9 Operating Temperature Effects

As referenced in several earlier subsections, the study data indicated that operating temperature had a significant effect on leak incident rates. Generally, the higher the operating temperature, the higher the resulting incident rate. This data is presented in Table 4-9.

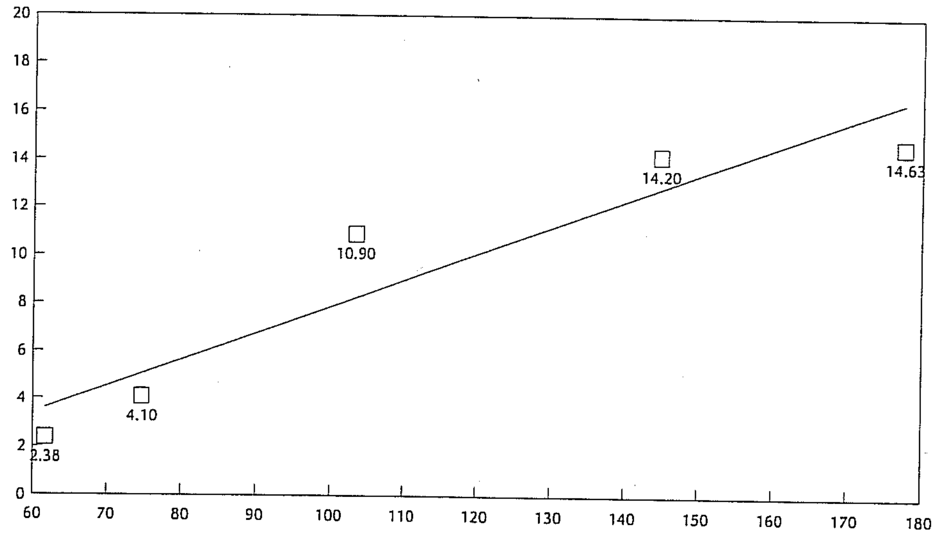
Table 4-9
Incident Rates By Normal Operating Temperature
(Incidents Per 1,000 Mile Years)

Cause of Incident	0 - 69°F	70 - 99°F	100 - 129°F	130 - 159°F	160°F +
External Corrosion	0.48	1.33	7.11	11.36	11.31
Internal Corrosion	0.00	0.21	0.32	0.57	0.08
3rd Party - Construction	1.91	0.94	0.95	0.57	0.60
3rd Party - Farm Equipment	0.00	0.30	0.47	0.00	0.08
3rd Party - Train Derailment	0.00	0.04	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.06	0.16	0.00	0.15
3rd Party - Other	0.00	0.24	0.16	0.00	0.15
Human Operating Error	0.00	0.11	0.00	0.00	0.23
Design Flaw	0.00	0.04	0.00	0.00	0.00
Equipment Malfunction	0.00	0.24	0.16	0.57	0.98
Maintenance	0.00	0.09	0.16	0.00	0.00
Weld Failure	0.00	0.19	0.32	0.00	0.60
Other	0.00	0.21	1.11	1.14	0.45
Total	2.38	4.01	10.90	14.20	14.63
Number of Mile Years	2,097	46,641	6,332	1,760	13,260
Mean Year Pipe Constructed	1960	1959	1953	1947	1951
Mean Operating Temperature (°F)	61.66	74.72	103.37	144.84	177.63
Mean Diameter (inches)	8.62	12.58	11.88	9.92	12.96
Average Spill Size (barrels)	12	480	72	7	601
Average Damage ($US 1983)	48,407	244,643	36,214	10,465	95,863

Incident Rates By Normal Operating Temperature
Incidents Per 1,000 Mile Years

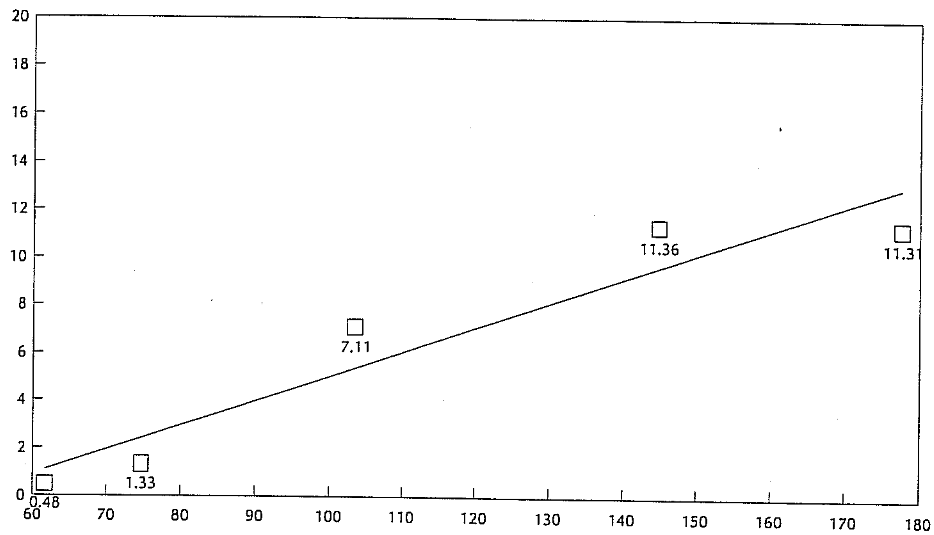


Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Normal Operating Temperature
Incidents Per 1,000 Mile Years



Normal Operating Temperature (°F)

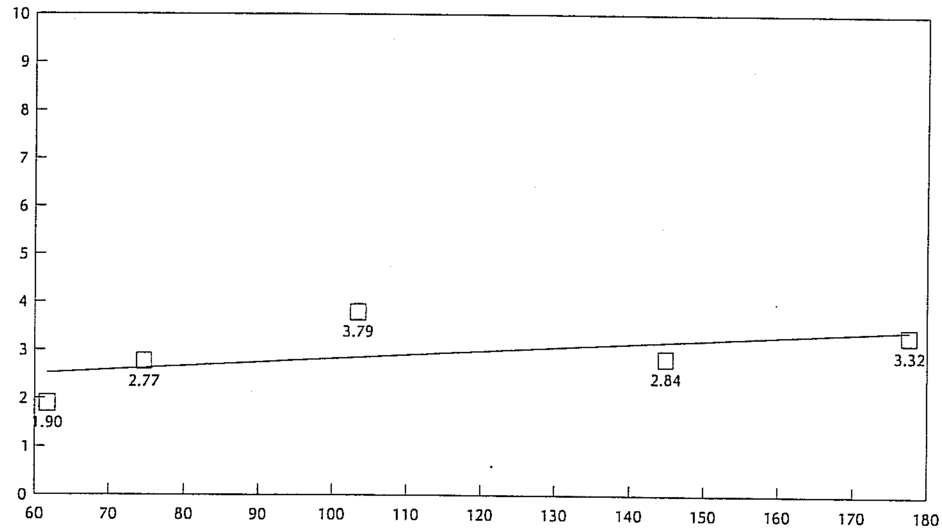
Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Normal Operating Temperature
Incidents Per 1,000 Mile Years



Normal Operating Temperature (°F)

Ordinary Least Squares Line of Best Fit
Incident Rates for Other Causes By Normal Operating Temperature
(Excludes All External Corrosion Incidents)

Incidents Per 1,000 Mile Years



Normal Operating Temperature (°F)

With the exception of the relatively new pipelines operating at above 180°F (most were built around 1979), higher operating temperatures were directly related to higher leak incident rates. However, the data also indicated that the pipelines operated between 130 and 159°F were also the oldest. As a result, a logistic regression was performed to determine whether or not pipe age was masking the pipe operating temperature effects. The logistic regression results indicated that while holding various factors constant, including pipe age, operating temperature was positively related to the probability of a leak occurring from external corrosion. Operating temperature was not statistically related, however, to the probability of leaks occurring from other causes.

Ordinary least squares lines of best fit were also calculated to evaluate the statistical relevance of this data. For all leaks, the line indicated an increase of 0.11 incidents per °F per 1,000 mile years, with an *R squared* of 0.89. For external corrosion leaks only, the regression resulted in an increase of 0.10 incidents per °F per 1,000 mile years, with an *R squared* of 0.91. For all leaks, excluding external corrosion leaks, the regression resulted in an increase of 0.0077 incidents per °F per 1,000 mile years, with an *R squared* of only 0.28, which reaffirms the logistical regression results that the probability of leaks occurring from other causes was not affected by operating temperature.

The data also indicated that spill sizes and monetary damage did not appear to be affected by operating temperature.

4.10 Pipe Diameter Effects

The variance in leak incident rates between pipe diameter ranges has been discussed somewhat in preceding subsections. A good deal of variance exists, as evidenced by the data presented in Table 4-10.

To begin with, the leak incident rate for pipe 7" in diameter and less was over three times that for pipe larger than 20" in diameter, 10.35 versus 3.17 incidents per 1,000 mile years. This is especially noteworthy since the mean operating temperature for the small diameter pipe was only 77.9°F, the lowest of any diameter range. However, the age of pipe in this category and in the 8-10 inch category was fairly old, which would tend to result in higher incident rates, as we have already seen.

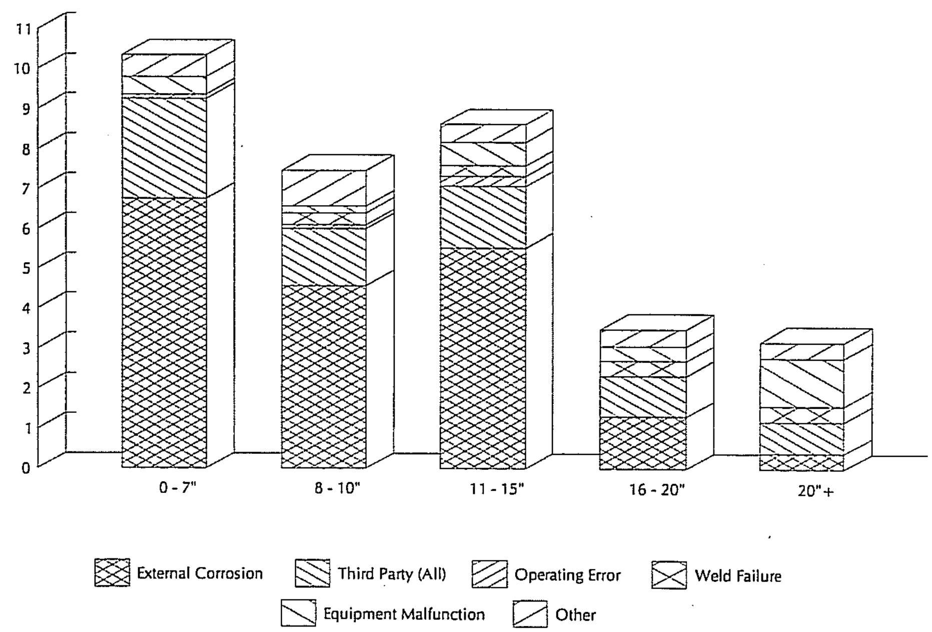
The category of pipe in the 11-15 inch diameter range also had a relatively high incident rate (8.62 incidents per 1,000 mile years). Although these lines were a good deal newer, they operated at a higher mean operating temperature.

Surprisingly, the 16-20 inch pipe diameter range had a relatively low leak rate (3.49 incidents per 1,000 mile years), despite having the highest mean operating temperature range.

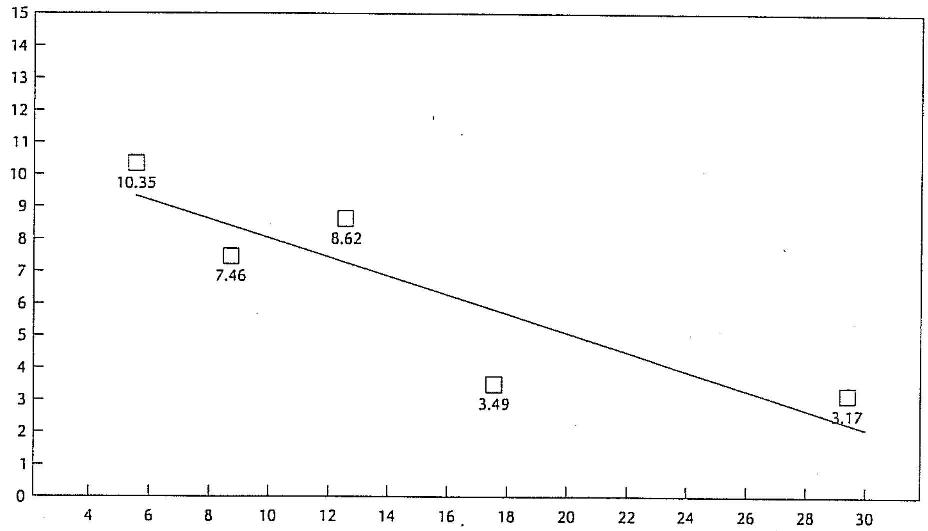
Table 4-10
Incident Rates By Pipe Diameter
(Incidents Per 1,000 Mile Years)

Cause of Incident	0 - 7"	8 - 10"	11 - 15"	16 - 20"	20"+
External Corrosion	6.75	4.56	5.51	1.31	0.40
Internal Corrosion	0.33	0.27	0.13	0.07	0.00
3rd Party - Construction	1.96	0.83	0.97	0.36	0.79
3rd Party - Farm Equipment	0.33	0.27	0.00	0.51	0.00
3rd Party - Train Derailment	0.00	0.00	0.06	0.07	0.00
3rd Party - External Corrosion	0.22	0.13	0.06	0.00	0.00
3rd Party - Other	0.00	0.20	0.45	0.07	0.00
Human Operating Error	0.11	0.10	0.26	0.00	0.00
Design Flaw	0.00	0.03	0.00	0.00	0.40
Equipment Malfunction	0.44	0.17	0.58	0.36	1.19
Maintenance	0.00	0.03	0.06	0.15	0.00
Weld Failure	0.00	0.30	0.26	0.36	0.40
Other	0.22	0.57	0.26	0.22	0.00
Total	10.35	7.46	8.62	3.49	3.17
Number of Mile Years	9,183	30,021	15,435	13,760	2,525
Mean Year Pipe Constructed	1951	1948	1962	1964	1984
Mean Operating Temperature (°F)	77.90	94.11	104.81	108.44	91.17
Mean Diameter (inches)	5.6	8.7	12.6	17.6	29.4
Average Spill Size (barrels)	55	190	489	1,980	88
Average Damage ($US 1983)	18,139	63,018	432,382	130,807	354,158

Incident Rates By Pipe Diameter
Incidents Per 1,000 Mile Years

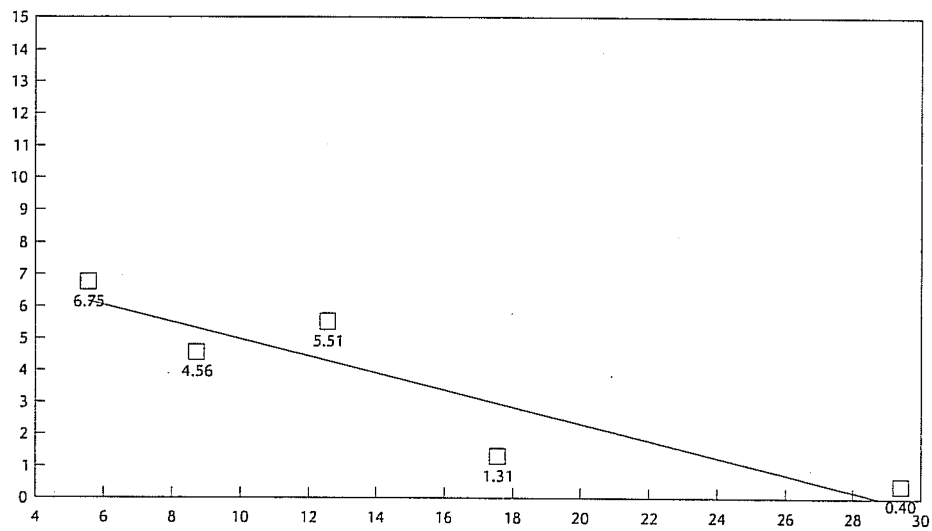


Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Pipe Diameter
Incidents Per 1,000 Mile Years



Pipe Diameter (inches)

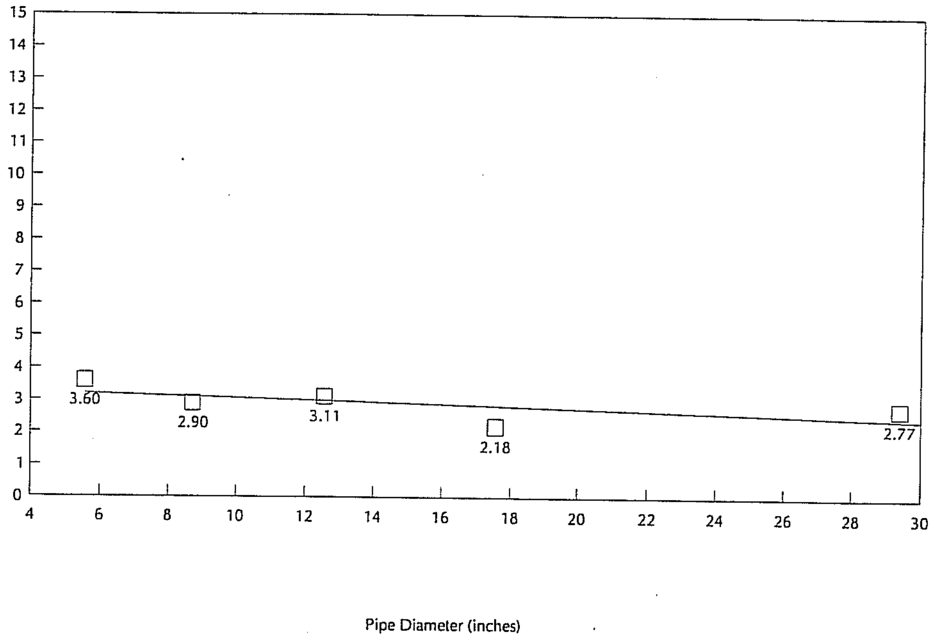
Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Pipe Diameter
Incidents Per 1,000 Mile Years



Pipe Diameter (inches)

Ordinary Least Squares Line of Best Fit
Incident Rates For Other Causes By Pipe Diameter
Excludes All External Corrosion Incidents

Incidents Per 1,000 Mile Years



The largest pipe, over 20 inches in diameter, had the lowest leak incident rate, 3.17 incidents per 1,000 mile years. However, this pipe was the newest of any category, with a mean year of pipe construction of 1984. The mean operating temperature was moderate.

Three ordinary least squares lines of best fit were prepared using this data. The first, performed using all data, indicated an overall reduction in the leak incident rate of 0.29 incidents per diameter inch per 1,000 mile years, with an *R squared* of 0.76. The second, included only external corrosion leaks; it indicated a reduction of 0.26 incidents per diameter inch per 1,000 mile years, with an *R squared* of 0.82. The third was performed using all leaks except external corrosion caused leaks; it resulted in a reduction of only 0.03 incidents per diameter inch per 1,000 mile years, with an *R squared* of 0.31. In short, there was a correlation between pipe diameter and the incident rate for external corrosion leaks, but not for leaks caused by other factors. There are several possible explanations for this correlation:

- Larger diameter pipelines represent a larger capital investment for the pipeline operator. As a result, there may be a greater proportion of the operators' resources directed toward their construction, operation, and maintenance.

- The larger diameter lines are often more important to the operators' overall operation and/or revenue generation. As a result, they may receive more attention.

- The larger lines are likely to create a greater perceived risk in the event of their rupture. This could also cause an operator to direct more resources to their protection.

4.11 Leak Detection Systems

The data was sorted into pipelines with some sort of supervisory control and data acquisition (SCADA) systems and those without. 85% of the regulated hazardous liquid pipelines hae SCADA systems. The leak incident rate for pipelines without these types of systems was almost twice the incident rate for systems with SCADA, 11.00 versus 6.29 incidents per 1,000 mile years. However, *this does not indicate that SCADA systems reduce leak incident rates.*

It should be noted that in general, the pipe with SCADA was seven years newer, had an operating temperature about 7°F higher, and had a mean diameter 3" greater than the systems without SCADA. We have already seen that these factors did affect incident rates. However, adding meters and telecommunications equipment to provide a SCADA system does not.

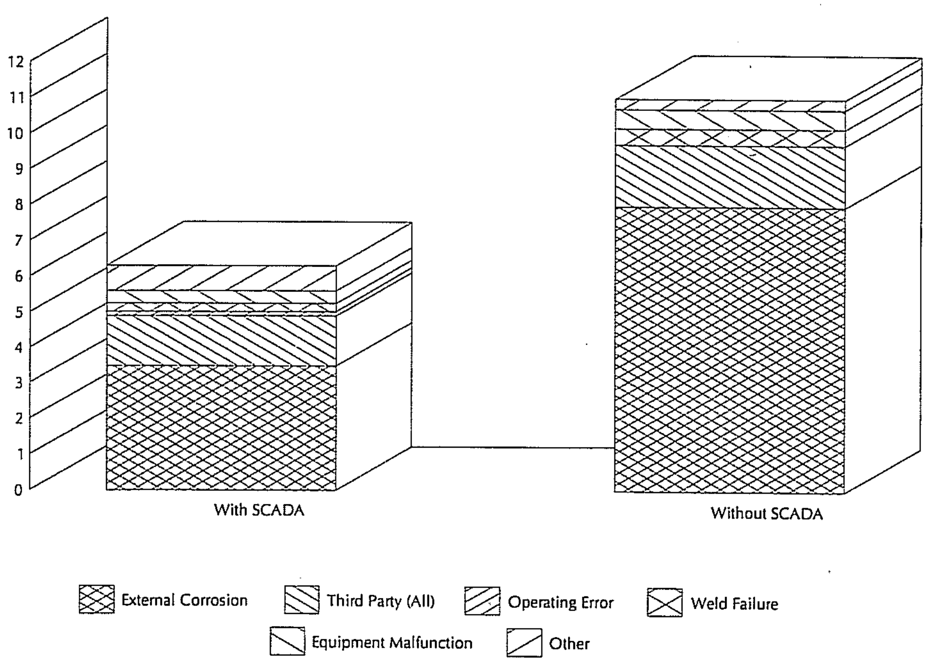
Table 4-11
Incidents By Leak Detection System
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	With SCADA		Without SCADA	
	Number	Rate	Number	Rate
External Corrosion	214	3.49	87	7.98
Internal Corrosion	13	0.21	1	0.09
3rd Party - Construction	53	0.86	11	1.01
3rd Party Farm Equipment	15	0.24	3	0.28
3rd Party - Train Derailment	2	0.03	0	0.00
3rd Party - External Corrosion	5	0.08	2	0.18
3rd Party - Other	11	0.18	3	0.28
Human Operating Error	8	0.13	0	0.00
Design Flaw	2	0.03	0	0.00
Equipment Malfunction	21	0.34	6	0.55
Maintenance	5	0.08	0	0.00
Weld Failure	14	0.23	5	0.46
Other	23	0.37	2	0.18
Total	386	6.29	120	11.00
Number of Mile Years	61,351		10,904	
Mean Year Pipe Constructed	1952		1945	
Mean Operating Temperature (°F)	114.3		107.0	
Mean Diameter (inches)	12.4		9.5	
Average Spill Size (barrels)	476.7		157.6	
Average Damage ($US 1983)	153,937		55,215	

Incident Rate Comparison

Incidents Per 1,000 Mile Years



It's interesting to note that the average spill size was nearly 3 times greater for pipelines with SCADA systems than those without. This was surprising, since it is generally accepted that SCADA systems provide a means of detecting leaks quickly, minimizing spill volumes. However, pipe diameter, fluid viscosity, line hydraulics and other factors also affect spill volumes. Assuming a mean 0.25" wall thickness and all other factors being equal, one would have expected a 75% greater spill volume from the relatively large diameter pipe with SCADA systems.

4.12 Cathodic Protection System

As indicated in Table 4-1, nearly 60% of the leaks on California's regulated pipeline systems were caused by external corrosion. As a result, we attempted to evaluate the effectiveness of cathodic protection systems and cathodic protection surveys. This section reviews applicable regulations and the data collected during the study.

Generally, 49 CFR 195.414 requires that all interstate pipelines which have an effective external coating must be cathodically protected, except for break out tank areas and buried pump station piping. The California Pipeline Safety Act requires that all intrastate pipelines be brought into compliance with these federal regulations according to a graduated five year schedule; all intrastate lines, including those which operate at less than 20% SMYS, were scheduled to comply by January 1, 1991. In other words, all regulated externally coated pipelines were required to have cathodic protection systems installed by the end of the study period.

49 CFR 195.416 requires that the cathodic protection systems on all cathodically protected interstate pipelines be inspected at least once each calendar year, at intervals not exceeding 15 months. In addition, each interstate pipeline operator is required to inspect their cathodic protection system rectifiers at intervals not exceeding two and one-half months, but at least six times a year. The California Pipeline Safety Act incorporates these requirements by reference for intrastate pipelines.

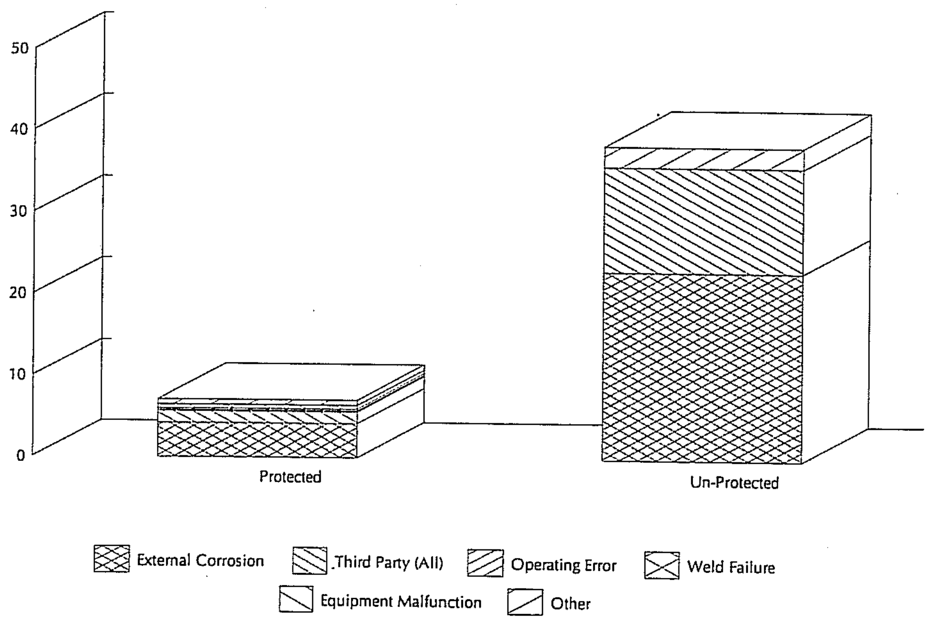
Nearly 100% of the regulated hazardous liquid pipelines were protected by either impressed current or sacrificial anode cathodic protection systems. We did not find a statistically relevant difference in the effect on leak incident rates between the two types of systems. However, we found a significant difference between protected and unprotected pipelines. As depicted in Table 4-12, unprotected pipelines had an external corrosion leak incident rate over five times higher than protected lines.

This is especially noteworthy since the unprotected lines, although a small sample, were much newer. They also operated at a higher mean operating temperature and were smaller in diameter.

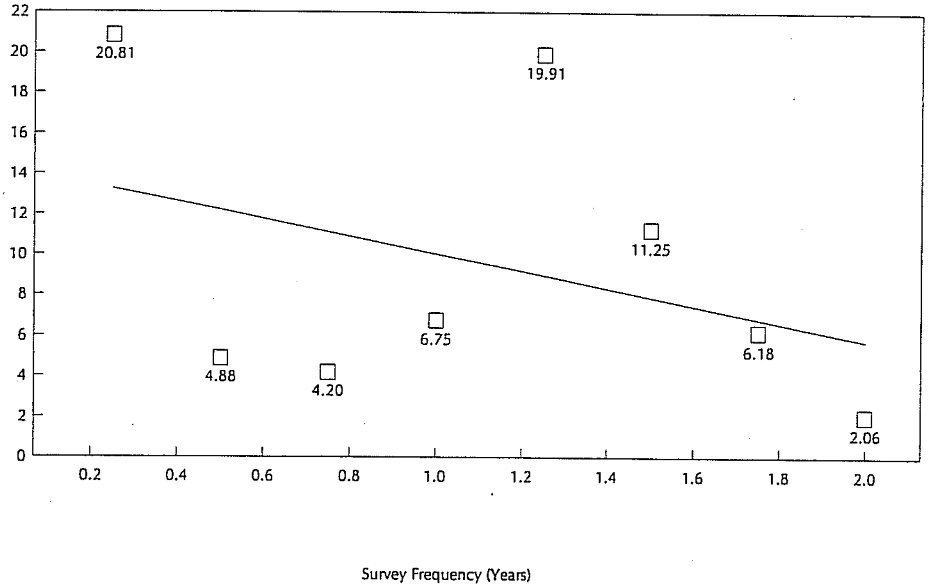
Table 4-12
Cathodic Protection System
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Protected Lines		Un-Protected Lines	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	295	4.23	9	23.12
Internal Corrosion	14	0.20	0	0.00
3rd Party - Construction	64	0.92	1	2.57
3rd Party Farm Equipment	18	0.26	0	0.00
3rd Party - Train Derailment	2	0.03	0	0.00
3rd Party - External Corrosion	5	0.07	1	2.57
3rd Party - Other	11	0.16	3	7.71
Human Operating Error	8	0.11	0	0.00
Design Flaw	2	0.03	0	0.00
Equipment Malfunction	27	0.39	0	0.00
Maintenance	5	0.07	0	0.00
Weld Failure	19	0.27	0	0.00
Other	25	0.36	1	2.57
Total	495	7.10	15	38.53
Number of Mile Years	69,756		389	
Mean Year Pipe Constructed	1957		1970	
Mean Operating Temperature (°F)	97		138	
Mean Diameter (inches)	12.4		8.8	
Average Spill Size (barrels)	418		39	
Average Damage ($US 1983)	145,091		82,760	

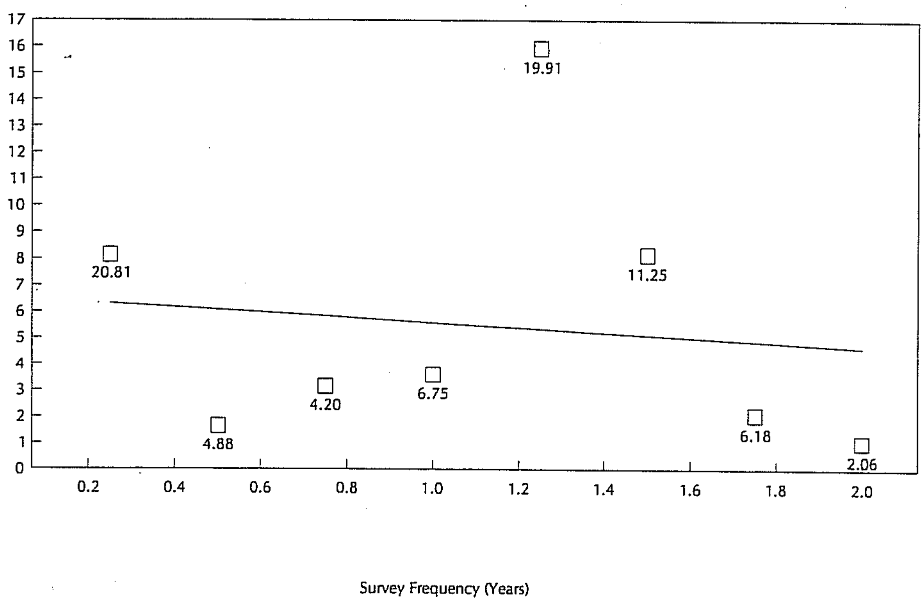
Incident Rate Comparison
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Cathodic Protection System Survey Frequency
Incident Rate Comparison - All Leak Incidents
(Incidents Per 1,000 Mile Years)



Ordinary Least Squares Line of Best Fit
Cathodic Protection System Survey Frequency
Incident Rate Comparison - External Corrosion Leak Incidents Only
(Incidents Per 1,000 Mile Years)



It is doubtful that whether or not a pipeline system was protected had any relation to spill volume or extent of damage; although this data has been presented for completeness. It does appear, however, that protection systems reduced the frequency of pipeline ruptures due to external corrosion.

Data was also collected regarding the frequency of cathodic protection surveys. Table 4-12 shows the overall and external corrosion only incident rates by the average frequency of cathodic protection surveys. Ordinary least squares lines of best fit were prepared to determine whether or not the frequency of cathodic protection surveys had any statistical relevance to leak incident rates. Surprisingly, the ordinary least squares lines of best fit showed a slightly decreasing incident rate with less frequent surveys. However, there was little if any statistical relevance to this data; the *R squared* values for all incidents and external corrosion only incidents were only 0.13 and 0.01 respectively.

A multinomial logistic regression analysis was performed to analyze this parameter. It indicated that the frequency of cathodic protection surveys was not statistically correlated with the external corrosion leak incident rate.

However, the data indicated that the probability of a leak occurring because of other causes was related to the frequency of cathodic protection surveys; that is, as the frequency of cathodic protection surveys decreased, the chance of an incident resulting from causes except external corrosion decreased as well. This effect was significant at the 1.9% probability level using the asymptotic t-distribution, holding variables such as length, year of construction and operating temperature constant. We believe that this result is circumstantial and does not indicate that cathodic protection surveys themselves decrease pipeline safety.

Table 4-12A presents the average cathodic protection survey interval compiled in a different format. The average cathodic protection survey interval was determined by dividing the total number of surveys conducted during the study period by 10 years, for each pipeline included in the study. The data was then combined into four categories: pipelines with average survey intervals up to one year; from over one year up to two years; from over two years to five years; and those from over five years up to ten years.

As indicated, the highest overall and external corrosion rate occurred in the group with cathodic protection surveys conducted between one and two years. This group had the highest mean operating temperature of any group, with a mean year of pipe construction near the average for all pipelines included in the study.

The group with the least frequent surveys (5.1 to 10.0 years) had the lowest overall and external corrosion rates. This is somewhat surprising since this was also the oldest pipe group. However, it had by far the lowest mean operating temperature.

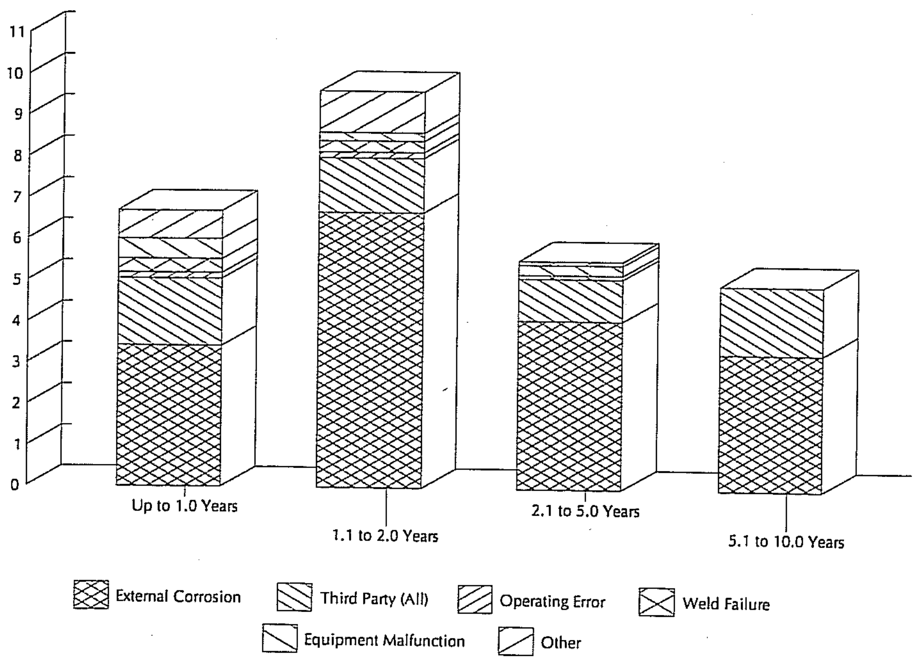
Table 4-12A
Average Cathodic Protection Survey Interval During Study Period
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	Up to 1.0 Years		1.1 to 2.0 Years		2.1 to 5.0 Years		5.1 to 10.0 Years	
	Total No.	Rate	Number	Rate	Number	Rate	Number	Rate
External Corrosion	146	3.43	100	6.68	48	4.10	4	3.33
Internal Corrosion	10	0.24	4	0.27	0	0.00	0	0.00
3rd Party - Construction	46	1.08	9	0.60	6	0.51	1	0.83
3rd Party Farm Equipment	10	0.24	7	0.47	1	0.09	0	0.00
3rd Party - Train Derailment	1	0.02	0	0.00	1	0.09	0	0.00
3rd Party - External Corrosion	3	0.07	0	0.00	3	0.26	1	0.83
3rd Party - Other	9	0.21	4	0.27	1	0.09	0	0.00
Human Operating Error	6	0.14	2	0.13	0	0.00	0	0.00
Design Flaw	1	0.02	1	0.07	0	0.00	0	0.00
Equipment Malfunction	21	0.49	3	0.20	3	0.26	0	0.00
Maintenance	5	0.12	0	0.00	0	0.00	0	0.00
Weld Failure	14	0.33	4	0.27	1	0.09	0	0.00
Other	13	0.31	10	0.67	1	0.09	0	0.00
Total	285	6.70	144	9.62	65	5.55	6	4.99
Number of Mile Years	42,524		14,961		11,713		1,202	
Mean Year Pipe Constructed	1954		1958		1962.8		1953	
Mean Operating Temperature (°F)	93.3		98.5		98.1		73.8	
Mean Diameter (Inches)	11.1		16.1		11.5		8.8	

Incident Rate Comparison

Incidents Per 1,000 Mile Years



4.13 Pipe Specification Effects

Another characteristic which could influence the propensity of leak incidents is the type of steel used in construction. Table 4-13 demonstrates that pipes constructed to different specifications had different incident rates. However, it must be recognized that other factors also affected these rates.

We were surprised to find that 78% of California's regulated hazardous liquid pipe was constructed of ASTM X grade material. Normally, this pipe is manufactured from relatively high quality steel, with more strictly controlled chemistry. The mean year of construction and mean operating temperature for X-grade pipe were 1960 and 97.6°F respectively.

22% of the pipe was constructed of ASTM A53 material. The incident rate for this material was nearly 2.7 times higher than that for X-grade material. However, this pipe was on average 10 years older, which would tend to increase the incident rate. However, the mean operating temperature was about 12°F lower, which would tend to reduce it.

An extremely small sample of pipe fell into the *other* category (less than 1%). However, the leak incident rate for this sample was very high, nearly 14 times that of X-grade pipe. Although the pipe had a mean age nearly 10 years older, it operated at a mean operating temperature roughly 30°F cooler.

4.14 Pipe Type Effects

Table 4-14 presents the study data by the type of pipe installed. The data sample was broken down into five categories: submerged arc welded (SAW), seamless (SMLS), electric resistance welded (ERW), lap welded (LW) and other. It was distributed as follows:

Pipe Type	Percentage of Sample
Electric Resistance Welded	76.3%
Seamless	16.8%
Lap Welded	4.0%
Other	2.0%
Submerged Arc Welded	0.9%

Table 4-13
Incidents By Pipe Specification
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	X-Grade Number	X-Grade Rate	A53 and Grade B Number	A53 and Grade B Rate	Other Number	Other Rate
External Corrosion	87	1.80	103	7.64	8	41.72
Internal Corrosion	6	0.12	5	0.37	0	0.00
3rd Party - Construction	34	0.70	13	0.96	2	10.43
3rd Party Farm Equipment	10	0.21	5	0.37	0	0.00
3rd Party - Train Derailment	2	0.04	0	0.00	0	0.00
3rd Party - External Corrosion	2	0.04	3	0.22	0	0.00
3rd Party - Other	11	0.23	1	0.07	0	0.00
Human Operating Error	3	0.06	2	0.15	0	0.00
Design Flaw	0	0.00	1	0.07	0	0.00
Equipment Malfunction	16	0.33	9	0.67	0	0.00
Maintenance	2	0.04	1	0.07	0	0.00
Weld Failure	14	0.29	4	0.30	0	0.00
Other	13	0.27	2	0.15	1	5.21
Total	200	4.13	149	11.05	11	57.36
Number of Mile Years	48,412		13,489		192	
Mean Year Pipe Constructed	1960		1950		1950	
Mean Operating Temperature (°F)	97.6		85.3		67.1	
Mean Diameter (inches)	13.1		8.8		8.9	
Average Spill Size (barrels)	757		63		24	
Average Damage ($US 1983)	282,182		109,230		32,998	

Incident Rate Comparison
Incidents Per 1,000 Mile Years

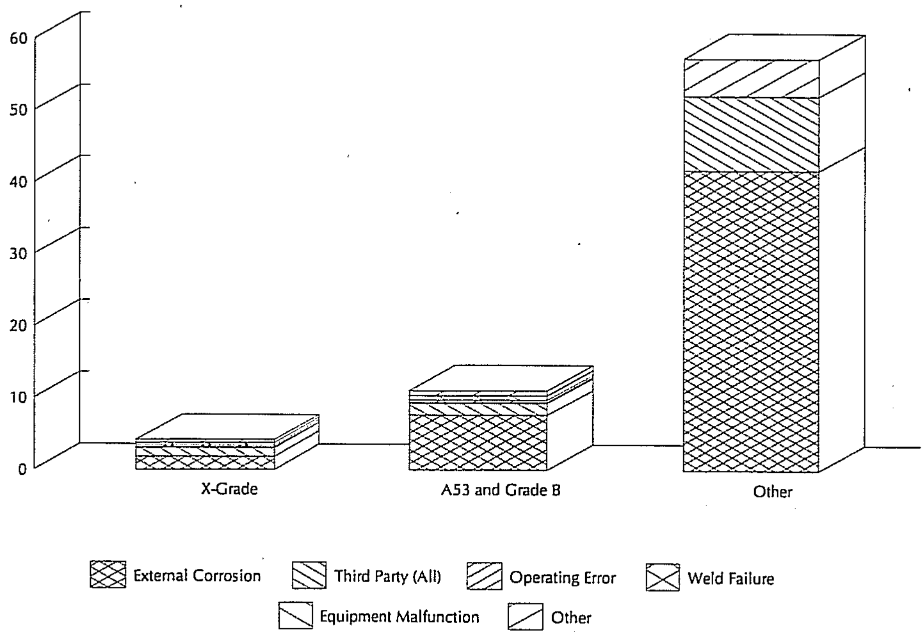
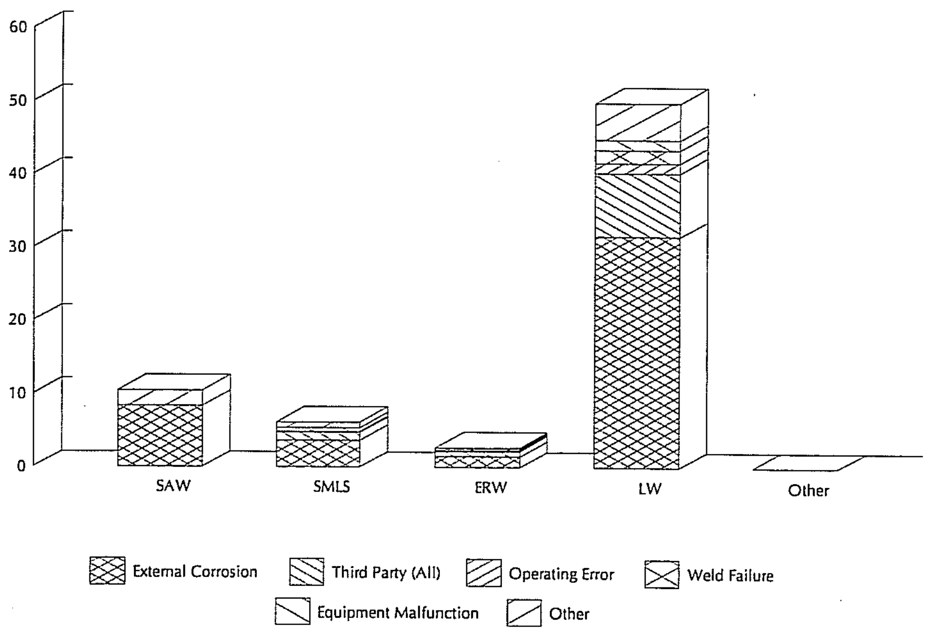


Table 4-14
Incident Rates By Pipe Type
(Incidents Per 1,000 Mile Years)

Cause of Incident	SAW	SMLS	ERW	LW	Other
External Corrosion	8.35	3.66	1.47	31.59	0.00
Internal Corrosion	2.09	0.22	0.02	1.83	0.00
3rd Party - Construction	0.00	0.86	0.45	6.41	0.00
3rd Party - Farm Equipment	0.00	0.22	0.02	1.83	0.00
3rd Party - Train Derailment	0.00	0.00	0.02	0.00	0.00
3rd Party - External Corrosion	0.00	0.00	0.09	0.00	0.00
3rd Party - Other	0.00	0.00	0.12	0.46	0.00
Human Operating Error	0.00	0.11	0.05	1.37	0.00
Design Flaw	0.00	0.00	0.00	0.46	0.00
Equipment Malfunction	0.00	0.54	0.17	1.37	0.00
Maintenance	0.00	0.11	0.00	0.46	0.00
Weld Failure	0.00	0.00	0.12	1.83	0.00
Other	0.00	0.43	0.14	2.29	0.00
Total	10.44	6.14	2.68	49.90	0.00
Number of Mile Years	479	9,280	42,112	2,184	1,106
Mean Year Pipe Constructed	1978	1951	1963	1933	1952
Mean Operating Temperature (°F)	120.28	83.59	98.02	86.87	85.58
Average Spill Size (barrels)	5	83	285	87	0
Average Damage ($US 1983)	18,830	195,426	405,013	68,656	0

Incident Rates By Pipe Type
Incidents Per 1,000 Mile Years



The data indicated that lap weld pipe had a very high leak incident rate; nearly 50 incidents per 1,000 mile years. However, it was also the oldest pipe, with a mean year of construction of 1933.

Electric resistance welded (ERW) pipe had a comparatively low incidence of leaks, 2.7 incidents per 1,000 mile years. These leaks occurred on somewhat newer pipeline systems, with a mean year of construction of 1963; they also operated at a mean operating temperature near the mean for the entire pipe sample.

Seamless pipe observed an incident rate of 6.1 incidents per 1,000 mile years. However, this pipe sample was relatively old, with a mean year of construction of 1951. But the mean operating temperature was comparatively cool, 83.6°F.

Submerged arc welded pipe had a high incidence of leaks, 10.4 incidents per 1,000 mile years. This small pipe sample was relatively new, with a mean year of construction of 1978. However, the mean operating temperature was the highest of the sample, 120.3°F.

4.15 Operating Pressure Effects

Our analyses demonstrated that the relationship between normal operating pressure and the probability of pipe rupture was not statistically significant. Table 4-15 shows that there was considerable variance in the incident rate by pressure range. These differences, however, disappeared once variables such as age of pipe and operating temperature were controlled in the logistic regressions.

A simple ordinary least squares line of best fit was also determined using the overall leak data for each pressure range. The data indicated a declining leak incident rate as operating pressure increased, with an *R squared* of 0.32. However, as indicated above, the logistical regressions, which take other factors into account, did not indicate a correlation between operating pressure and leak incident rates.

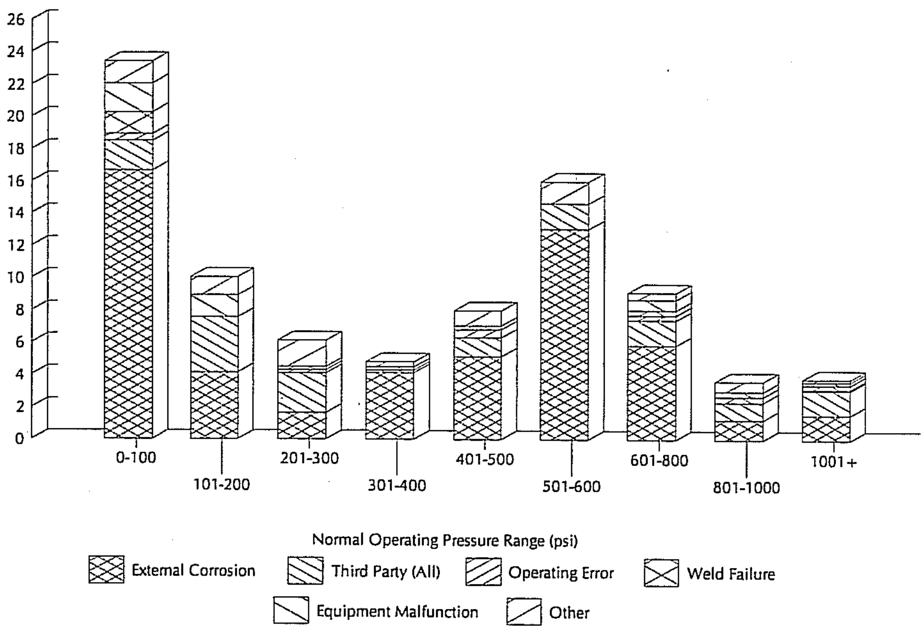
An ordinary least squares line of best fit was also prepared for spill size as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly 90 barrel increase in mean spill size per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.62. It should also be noted that mean pipe diameter was also slightly higher for pipelines operating within the higher operating pressure ranges; this would also skew the results in this direction.

A similar line of best fit was prepared for average damage as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly $37,000 ($US 1983) increase in average damager per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.58. However, as noted for spill volumes, pipe diameter variances would also generally affect spill damage.

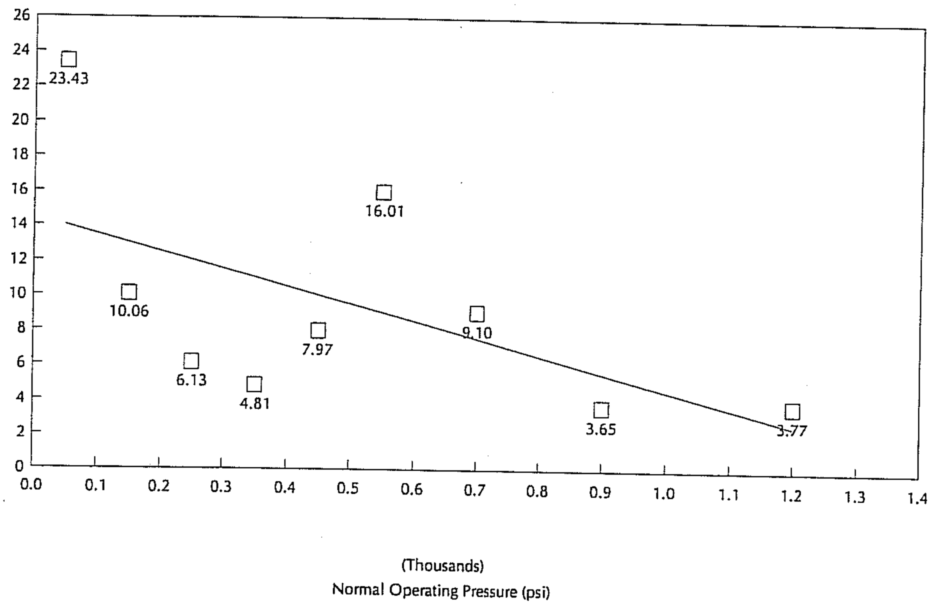
Table 4-15
Incident Rates By Normal Operating Pressure
(Incidents Per 1,000 Mile Years)

Cause of Incident	0-100 (psi)	101-200 (psi)	201-300 (psi)	301-400 (psi)	401-500 (psi)	501-600 (psi)	601-800 (psi)	801-1000 (psi)	1001+ (psi)
External Corrosion	16.67	4.11	1.63	4.12	5.16	13.05	5.83	1.26	1.58
Internal Corrosion	0.45	0.69	1.23	0.34	0.23	0.20	0.00	0.00	0.00
3rd Party - Construction	1.80	2.29	1.02	0.17	0.70	1.19	1.09	0.60	0.75
3rd Party - Farm Equipment	0.00	0.00	0.61	0.00	0.47	0.20	0.40	0.06	0.48
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14
3rd Party - External Corrosion	0.00	0.46	0.41	0.00	0.00	0.20	0.00	0.06	0.00
3rd Party - Other	0.00	0.69	0.41	0.00	0.00	0.00	0.10	0.36	0.14
Human Operating Error	0.45	0.00	0.20	0.00	0.47	0.00	0.30	0.00	0.07
Design Flaw	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.06	0.00
Equipment Malfunction	1.80	1.37	0.00	0.17	0.00	0.00	0.69	0.30	0.21
Maintenance	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.18	0.00
Weld Failure	1.35	0.00	0.20	0.00	0.23	0.00	0.30	0:36	0.27
Other	0.90	0.46	0.20	0.00	0.70	1.19	0.20	0.42	0.14
Total	23.43	10.06	6.13	4.81	7.97	16.01	9.10	3.65	3.77
Number of Mile Years	2,219	4,374	4,895	5,818	4,264	5,058	10,112	16,732	14,597
Average Year Pipe Constructed	1933	1954	1949	1940	1946	1934	1945	1958	1949
Average Operating Temperature (°F)	130.8	92.7	82.8	86.7	121.6	125.2	159.7	116.2	104.4
Average Diameter (inches)	9.9	11.0	8.6	12.7	8.7	9.3	11.1	16.4	11.7
Average Spill Size (barrels)	17	56	5	130	149	127	456	1,292	676
Average Damage ($US 1983, 1,000's)	59	71	38	50	26	13	70	167	586

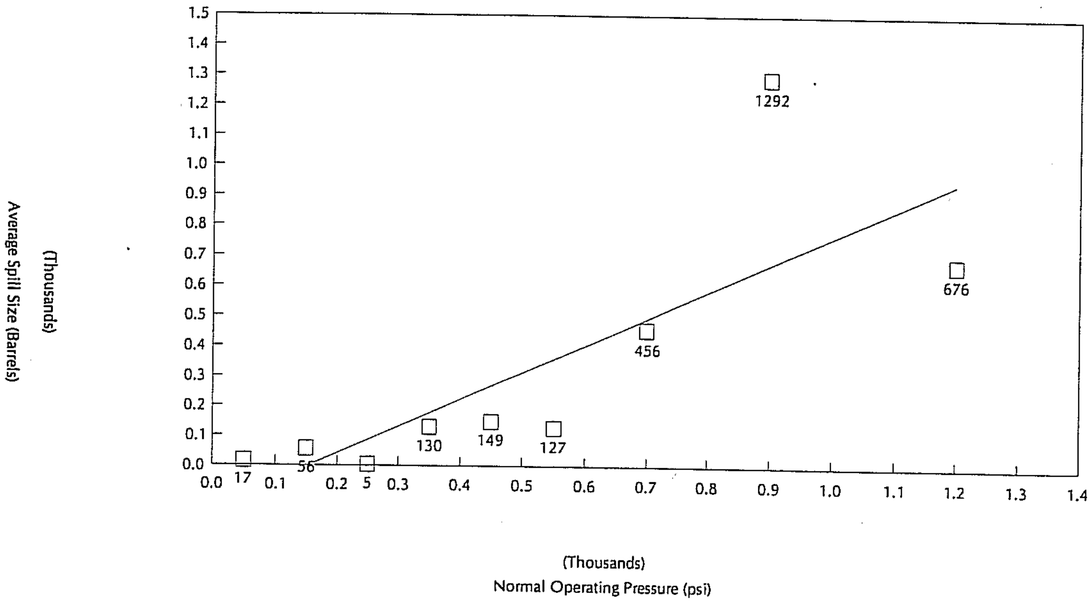
Incident Rates By Normal Operating Pressure
Incidents Per 1,000 Mile Years



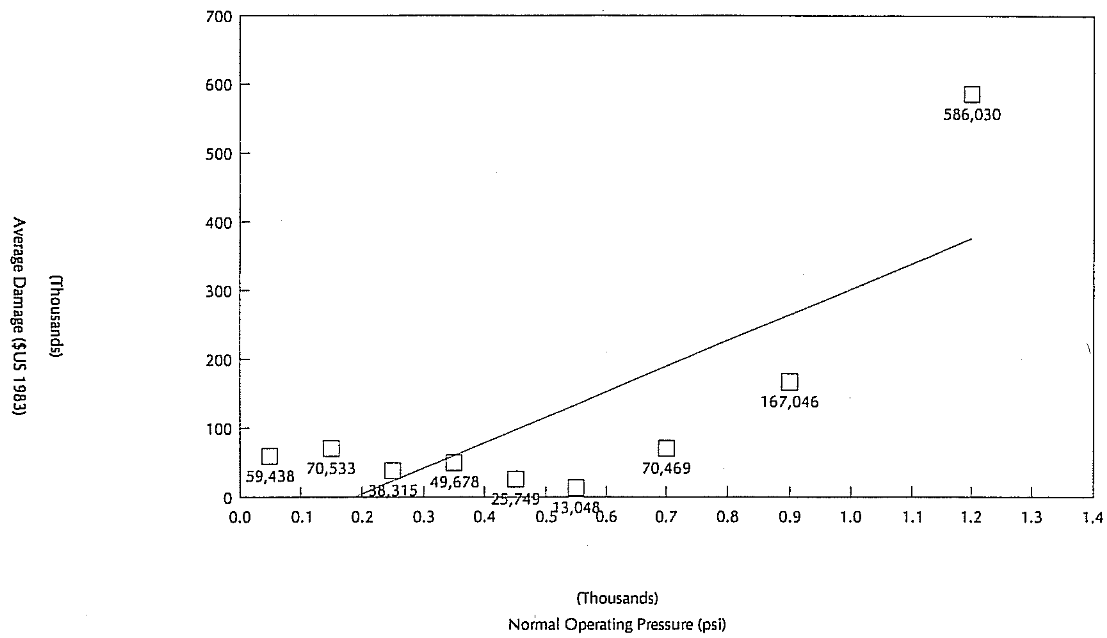
Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Normal Operating Pressure
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Average Spill Size By Normal Operating Pressure



Ordinary Least Squares Line of Best Fit
Average Damage By Normal Operating Pressure



4.16 External Pipe Coatings

This subsection examines the incident rates for various external pipe coatings. To accomplish this, the data sample was sorted into eight categories, which represented nearly all of the coatings installed on the pipelines included in this study. These coating types, their common and trade names, and the percentage of each in operation during the study period are presented below.

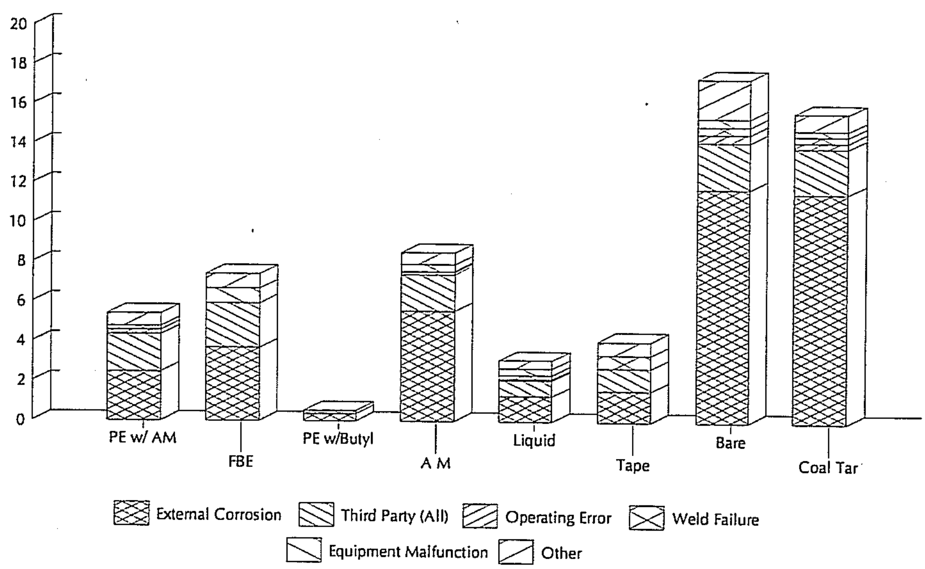
Coating Type	Percentage of Sample	Common/Trade Names
Extruded Polyethylene with Asphalt Mastic	6.5%	X-Tru-Coat Plexco EEC 60XT (X-Tru-Coat)
Fusion Bonded Epoxy	1.8%	FBE Mobilox Scotchcoat 206 or 202 Thin Film Epoxy
Extruded Polyethylene with Side Extruded Butyl	7.6%	Pritec
Extruded Asphalt Mastic	24.9%	Somastic Asphalt Mastic
Liquid Systems	41.6%	Coal Tar Epoxy Carboline Epoxy
Mill Applied Tape	6.0%	Polyken Tape YG III Plicoflex Raychem Hotclad Synergy
Coal Tar	4.7%	Coal Tar or Asphalt Enamel Wrapped
Bare Pipe	6.8%	N/A

Table 4-16 presents the incident rates by coating type. Although pipe age and operating temperatures had the greatest effect, there did appear to be differences in performance between the coating systems. As noted earlier in Table 4-1, the average external corrosion incident rate for all pipe included in this study was 4.18 incidents per 1,000 mile years. Generally, the more modern coatings had external corrosion incident rates lower than average, some significantly lower. The older, extruded asphalt mastic systems had external corrosion incident rates slightly higher than average. Somewhat surprisingly, the coal tar and asphalt enamel wrapped pipe had an external corrosion incident rate nearly as high as the bare pipe.

Table 4-16
Incident Rates By Coating Type
(Incidents Per 1,000 Mile Years)

Cause of Incident	Extruded PE with Asphalt Mastic	Fusion Bonded Epoxy	Extruded PE with Side Extruded Butyl	Extruded Asphalt Mastic	Liquid Systems	Mill Applied Tape	Bare Pipe	Coal Tar or Asphalt Enamel Wrapped
External Corrosion	2.49	3.71	0.36	5.56	1.27	1.58	11.77	11.59
Internal Corrosion	0.21	0.00	0.00	0.27	0.20	0.00	0.20	0.29
3rd Party - Construction	1.04	0.00	0.18	1.31	0.49	0.45	1.60	1.45
3rd Party - Farm Equipment	0.42	2.22	0.00	0.22	0.00	0.45	0.00	0.87
3rd Party - Train Derailment	0.21	0.00	0.00	0.00	0.03	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.00	0.00	0.16	0.13	0.00	0.00	0.00
3rd Party - Other	0.21	0.00	0.00	0.16	0.16	0.23	0.80	0.00
Human Operating Error	0.21	0.00	0.00	0.11	0.07	0.00	0.40	0.29
Design Flaw	0.00	0.00	0.00	0.05	0.00	0.23	0.00	0.00
Equipment Malfunction	0.21	0.74	0.00	0.33	0.33	0.00	0.40	0.29
Maintenance	0.00	0.00	0.00	0.11	0.03	0.00	0.00	0.00
Weld Failure	0.00	0.00	0.00	0.05	0.20	0.68	0.40	0.29
Other	0.42	0.74	0.00	0.16	0.20	0.45	1.80	0.58
Total	5.40	7.41	0.53	8.51	3.09	4.06	17.35	15.65
Number of Mile Years	4,814	1,349	5,625	18,342	30,700	4,435	5,013	3,450
Mean Year Pipe Constructed	1974	1984	1973	1956	1959	1984	1948	1962
Mean Operating Temperature (°F)	107.4	115.6	105.8	80.5	98.1	104.6	103.8	105.8

Incident Rates By Coating Type
Incidents Per 1,000 Mile Years



PE = Extruded Polyethylene
AM = Extruded Asphalt Mastic
Tape = Mill Applied Tape

FBE = Fusion Bonded Epoxy
Liquid = Epoxy Liquid Applied Systems
Butyl = Side Extruded Butyl Rudder

Bare (uncoated) lines, which comprised roughly 7% of the total, suffered the highest external corrosion and overall incident rates; in fact, these values were almost three times the average values for all pipelines included in the study. It should also be noted however, that these lines had the oldest mean year of pipe construction and a mean operating temperature higher than average.

The coal tar and asphalt enamel wrapped pipelines, about 5% of the total, had an external corrosion rate nearly as high as the bare pipelines. These lines were operated at an average of 8°F above the mean operating temperature; they were also on average 5 years newer than the mean.

Extruded asphalt mastic coated pipe, roughly one-quarter of the total, had the third highest external corrosion and overall incident rates. This pipe had the second oldest mean year of pipe construction and the lowest mean operating temperature.

Somewhat surprisingly, the 2% of the total pipe coated with fusion bonded epoxy had the forth highest external corrosion and overall incident rates. The external corrosion incident rate for this coating was slightly below the overall average. This pipe was the newest sample included in the study, with a 1984 mean year of pipe construction. However, the operating temperature was the highest of the group, 115.6°F.

Extruded polyethylene with asphalt mastic, liquid systems and mill applied tape had external corrosion incident rates roughly one-half to one-third the average. The overall incident rates for these coatings were also considerably lower than the average. The mean pipe age and mean operating temperatures varied considerably among these groups. However, the pipe was generally much newer than average, with higher than average operating temperatures.

The lowest incident rates were observed on pipe with extruded polyethylene with side extruded butyl, which comprised 8% of the total. The observed external corrosion and overall incident rates for these pipelines were both less than one-tenth the average values. This pipe sample was relatively new, with a 1973 mean year of pipe construction. The mean operating temperature was moderately high, 105.8°F.

Difficulties were encountered performing multiple logit regressions using the coating type as an independent leak indicator. This occurred because the leak data and pipe data were gathered separately. Subsequently, the data were compiled using two separate databases. The coating type data was gathered for each segment of each pipeline within the state, resulting in tens of thousands of individual pipe segments. However, the leak data contained only the pipeline identification on which the leak occurred, as well as other pertinent data; the leak data did not specifically identify which segment of pipe suffered the leak. As a result, some manipulation of the data was necessary to perform the multiple logit analysis. The resulting analysis did indicate a correlation between coating type and leak incident rates.

4.17 High Risk Pipelines

The California Government Code, §51013.5 (f) prescribes criteria for identifying certain pipelines as *high risk*. The Code also specifies additional requirements for pipelines identified as such. It should be noted that these requirements only apply to intrastate pipelines; interstate pipelines are not subject to these additional requirements. Basically, the regulation requires the following intrastate pipelines to be considered *high risk*:

- have suffered two or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion or defect in the prior three years,

- have suffered three or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion, defects, or external forces, but not all due to external forces, in the prior three years,

- have suffered a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or defect of more than 50,000 gallons, or 10,000 gallons in a standard metropolitan statistical area, in the prior three years; or have suffered a leak due to corrosion or defect which the State Fire Marshal finds has resulted in more than 42 gallons of a hazardous liquid within the State Fire Marshal's jurisdiction entering a waterway in the prior three years; or have suffered a reportable leak of a hazardous liquid with a flash point of less than 140°F in the prior three years,

- are less than 50 miles long, and have experienced a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or a defect in the prior three years, or

- have experienced a reportable leak in the prior five years due to corrosion or defect, except during a certified hydrostatic pressure test, on a section of pipe more than 50 years old.

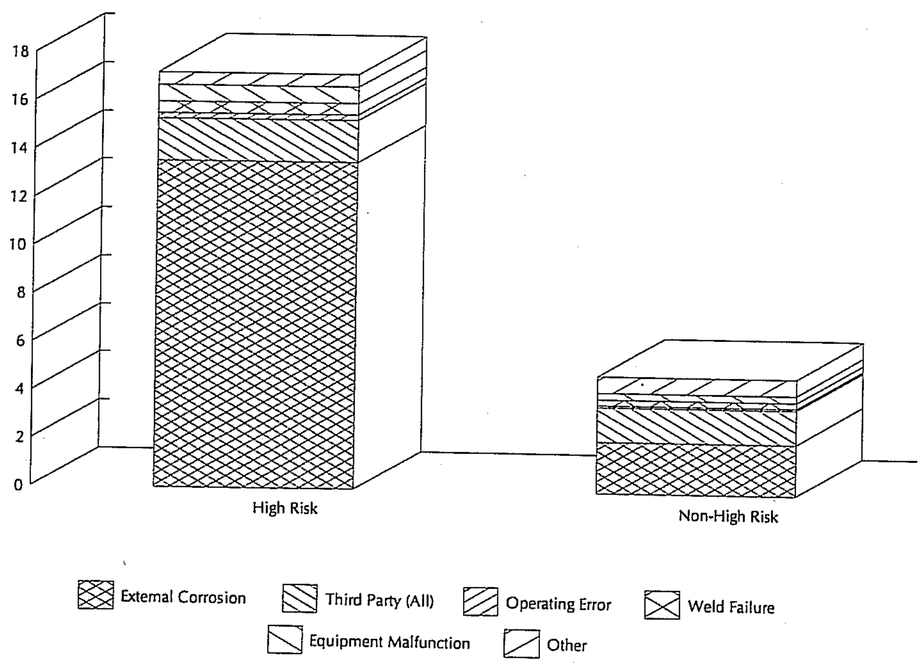
Intrastate pipelines meeting any of the above criteria, remain identified as *high risk* lines until 5 years pass without a reportable leak due to corrosion or defect. Basically these *high risk* pipelines must be hydrostatically tested every two years, instead of the generally required five year hydrostatic test interval for intrastate lines.

Table 4-17 presents the incident rate data for *high risk* versus non-*high risk* pipelines. The lines which were identified as *high risk* during our data gathering phase, were considered as *high risk* lines for the entire 10 year study period. By doing so, we were able to evaluate any resulting increase in pipeline safety.

Table 4-17
High Risk versus Non-High Risk Pipelines
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	High Risk		Non-High Risk	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	176	13.54	125	2.16
Internal Corrosion	2	0.15	12	0.21
3rd Party - Construction	11	0.85	53	0.91
3rd Party Farm Equipment	3	0.23	15	0.26
3rd Party - Train Derailment	0	0.00	2	0.03
3rd Party - External Corrosion	5	0.38	2	0.03
3rd Party - Other	4	0.31	10	0.17
Human Operating Error	3	0.23	5	0.09
Design Flaw	1	0.08	1	0.02
Equipment Malfunction	9	0.69	18	0.31
Maintenance	1	0.08	4	0.07
Weld Failure	6	0.46	13	0.22
Other	3	0.23	22	0.38
Total	224	17.24	282	4.86
Number of Mile Years	12,996		58,002	
Average Year Pipe Constructed	1950		1958	
Average Operating Temperature (°F)	130		91	
Average Diameter (inches)	12.6		12.3	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



As indicated in Table 4-17, the present criteria has done a good job of identifying lines with higher than average incident rates. Specifically, the *high risk* pipelines had an overall incident rate three and one-half times greater than the non-*high risk* lines. The external corrosion incident rate for these lines was over six times the rate for the non-*high risk* pipelines. The leak incident rate for all incident causes, except external corrosion, were fairly consistent between the two groups, 3.70 versus 2.70 incidents per 1,000 mile years for *high risk* and non-*high risk* pipelines respectively.

Although the data presented in Table 4-17 indicates that the present criteria for identifying *high risk* pipelines has identified these lines reasonably well, there are undoubtedly exceptions. We recommend that the CSFM consider using the data collected in this study to identify *high risk* pipelines. The data could be sorted and a leak incident rate could be calculated for each pipeline included in the study. High risk lines could then be identified as those with leak incident rates above some predetermined figure. If pursued, consideration should be given to establishing different limits for product and crude pipelines, since the risk to public safety differ.

For example, *high risk* pipelines could be those with an overall leak incident rate say 50% higher than average for product lines and maybe 100% higher than average for crude lines. Using the values presented earlier in Table 4-4, this would result in incident rate identification criteria of 20 and 7 incidents per 1,000 mile years for crude and product systems respectively.

Table 4-17A shows the leak incident history for *high risk* pipelines during the ten year study period. As indicated, the external corrosion and overall rates fluctuated significantly during the study period.

A simple ordinary least squares line of best fit was determined using the overall leak data for high risk pipelines. The data indicated a slight reduction in the overall incident rate during the study period. However, the statistical *R squared* was an extremely low 0.02. As a result, we do not believe that there has been a measurable decrease in overall incident rates as a result of the *high risk* pipeline program. On the other hand, we did not see an increase, which one may have expected since the mean age of pipe increased during the study period.

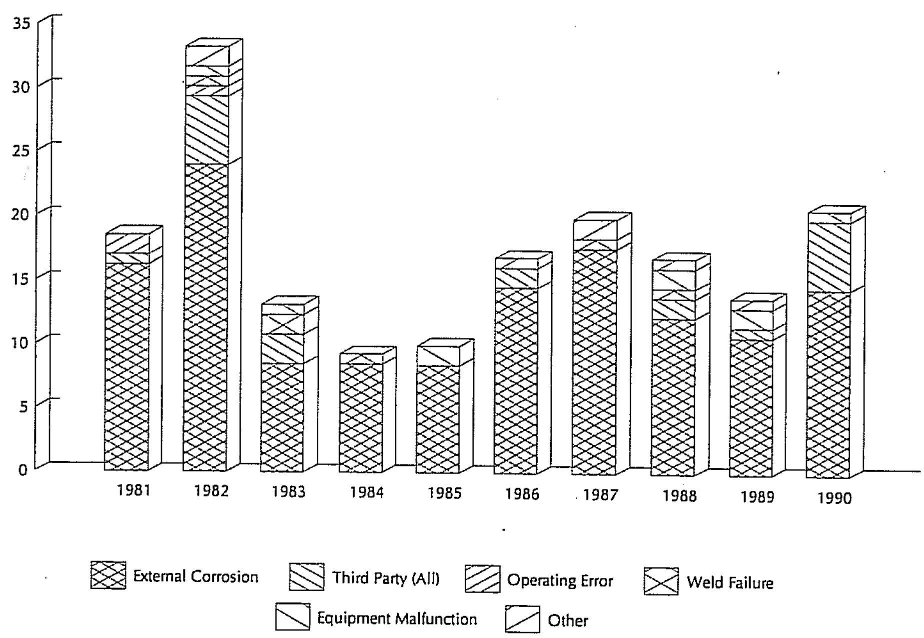
An ordinary least squares line of best fit was also prepared for *high risk* pipeline external corrosion leaks only. Once again, the data indicated a slight reduction in the external corrosion incident rate during the study period. But the resulting *R squared* was a very low 0.04. As a result, we do not believe that there has been a measurable decrease in external corrosion incident rates as a result of the *high risk* pipeline program. But as noted above, we did not see an increase either.

Similar analyses were also performed for leaks resulting from all causes except external corrosion, as well as for average spill sizes. Once again, these resulted in extremely low statistical *R squared* values. In all cases, we believe that the overall 10 year average values presented in Table 4-17 should be used.

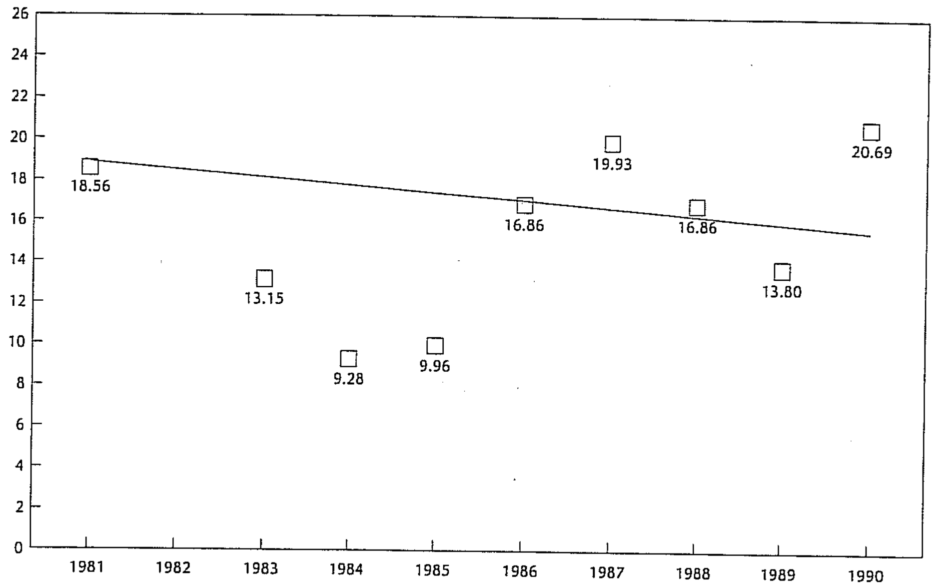
Table 4-17A
Incident Rates By Year of Study - High Risk Pipelines Only
(Incidents Per 1,000 Mile Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
External Corrosion	16.24	23.98	8.51	8.51	8.43	14.56	17.63	12.26	10.73	14.56
Internal Corrosion	0.00	0.00	0.00	0.00	0.00	0.00	1.53	0.00	0.00	0.00
3rd Party - Construction	0.00	4.64	0.77	0.00	0.00	0.00	0.00	0.77	0.77	1.53
3rd Party - Farm Equipment	0.00	0.00	0.77	0.00	0.00	0.77	0.00	0.77	0.00	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.83
3rd Party - Other	0.77	0.77	0.77	0.00	0.00	0.77	0.00	0.00	0.00	0.00
Human Operating Error	1.55	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Design Flaw	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00	0.00
Equipment Malfunction	0.00	0.77	0.77	0.00	1.53	0.00	0.00	1.53	1.53	0.77
Maintenance	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00
Weld Failure	0.00	0.77	1.55	0.77	0.00	0.00	0.77	0.77	0.00	0.00
Other	0.00	1.55	0.00	0.00	0.00	0.77	0.00	0.00	0.00	0.00
Total	18.56	33.26	13.15	9.28	9.96	16.86	19.93	16.86	13.80	20.69
Number of Mile Years	1,293	1,293	1,293	1,293	1,305	1,305	1,305	1,305	1,305	1,305
Mean Year Pipe Constructed	1949	1949	1949	1949	1950	1950	1950	1950	1950	1950
Mean Operating Temperature (°F)	131.0	131.0	131.0	130.9	130.4	130.4	130.4	130.4	130.4	130.4
Mean Diameter (inches)	12.6	12.6	12.6	12.6	12.6	12.5	12.6	12.6	12.6	12.6
Average Spill Size (barrels)	159.4	410.1	742.6	660.5	722.2	673.6	631.5	569.2	538.6	486.0
Average Damage ($1,000 US 1983)	5.5	22.3	74.4	72.3	95.4	130.8	108.7	100.4	92.8	91.4

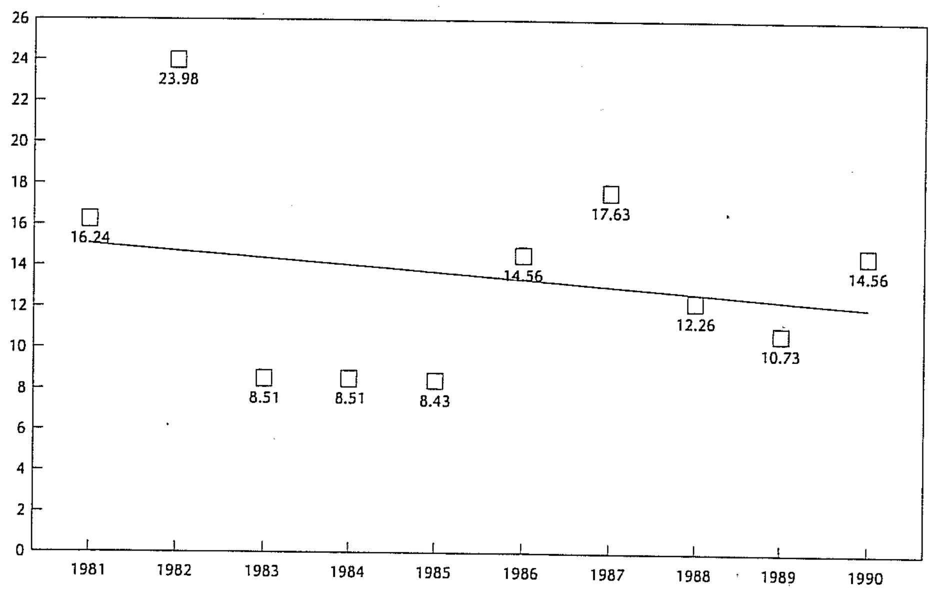
High Risk Pipeline Incident Rates By Year of Study
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
High Risk Pipeline Overall Incident Rates By Year of Study
Incidents Per 1,000 Mile Years

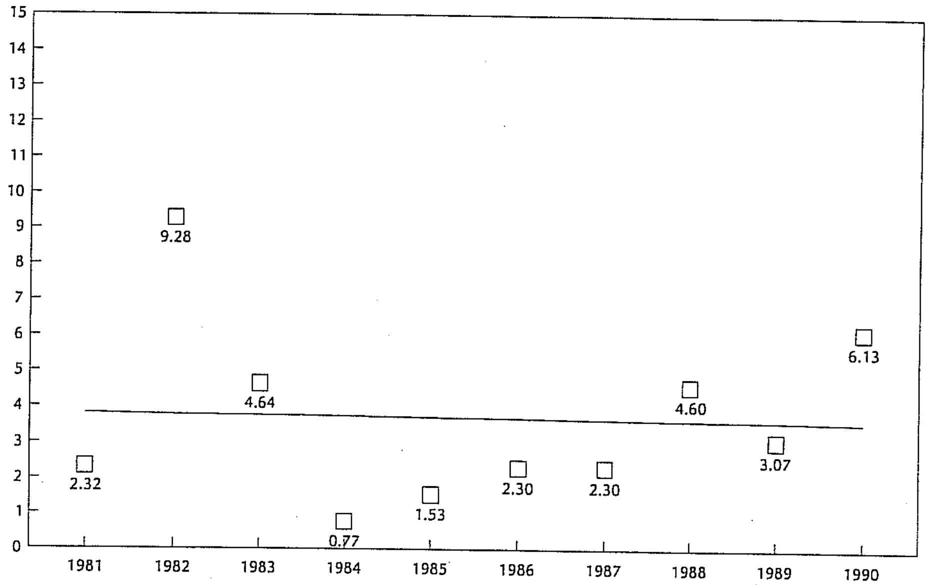


Ordinary Least Squares Line of Best Fit
High Risk Pipeline External Corrosion Incident Rates By Year of Study
Incidents Per 1,000 Mile Years

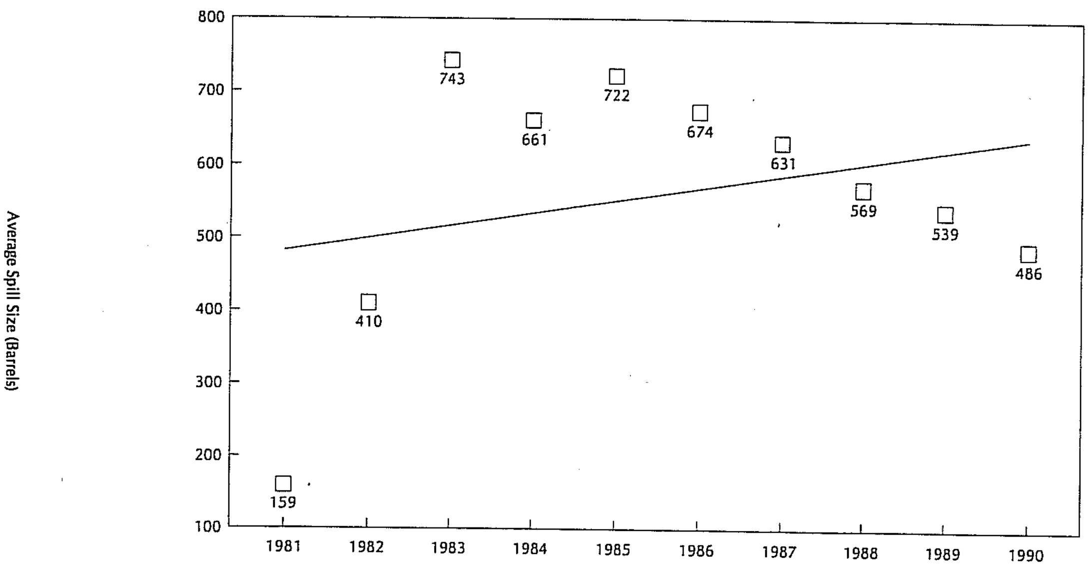


Ordinary Least Squares Line of Best Fit
High Risk Pipeline Incident Rates For Other Causes By Year of Study
(Excludes All External Corrosion Incidents)

Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
High Risk Pipeline Average Annual Spill Size (Barrels) By Year of Study



Considering the lack of a clear reduction in incident rates during the study period for *high risk* pipelines, it may be worthwhile to reconsider the requirements for these lines to more effectively reduce the likelihood of leaks. It does not appear as though the increased hydrostatic testing requirements have resulted in significant benefits. Since the vast majority of these leaks were caused by external corrosion, more benefits could likely be obtained by redirecting the monies currently expended on additional hydrostatic testing to other activities aimed at reducing external corrosion leaks (e.g. pipeline replacements, recoating, cathodic protection system upgrades, etc.).

The American Petroleum Institute conducted a survey of interstate pipeline operators in 1986-87. They found that the average cost of hydrostatic testing was $5,300 per mile. Using this figure and considering the roughly 1,300 miles of line in the current *high risk* inventory, at least $2,000,000 per year would be available to be redirected toward actions intended to prevent leaks. This would result from eliminating the current increased hydrostatic testing requirements for *high risk* lines.

4.18 Internal Inspections

During the last several years, there have been significant advances in the technologies available to internally inspect pipelines using *smart* pigs. These tools use several technologies to identify wall thinning, buckling, erosion, corrosion and other anomalies. These technologies, available from various vendors, differ greatly in their ability to identify and quantify various forms of damage and/or deterioration. Some are extremely precise and sophisticated, while others are much more general.

Unfortunately, most of these inspection tools are rather long. As a result, they require smooth, long radius bends to facilitate their passage; most will not traverse short radius elbows for example.

Out of the roughly 7,800 miles of regulated California pipelines, nearly 58% (4,495 miles) are capable of being inspected using these techniques, with little or no modification. 70% (3,128 miles) of these pipelines, which are capable of being inspected, have already been inspected in this manner.

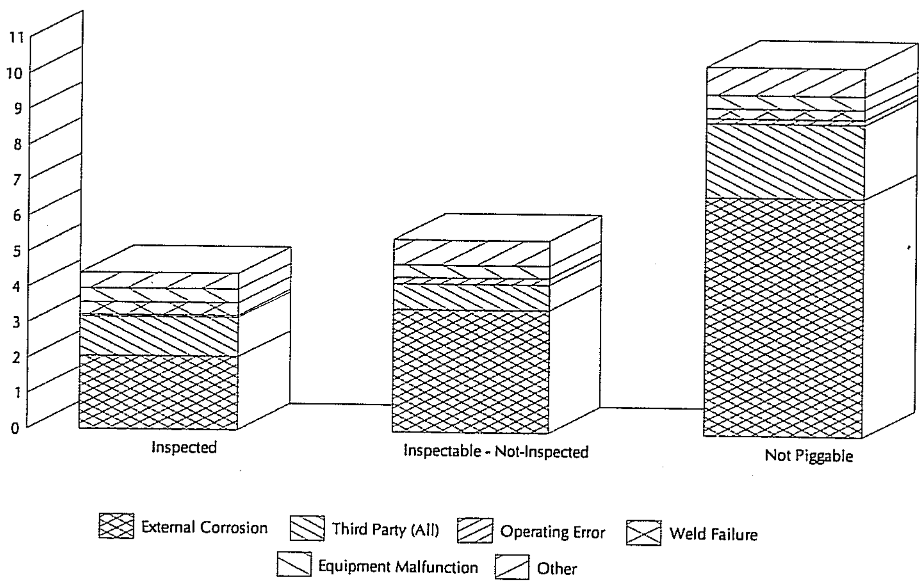
Table 4-18 presents a comparison of the incident rates for pipelines meeting three criteria:

- pipelines which have been internally inspected,
- pipelines which could be inspected with little or no modification, but had not been inspected by the end of the study period, and
- those pipelines which are not capable of passing an inspection pig without significant modification.

Table 4-18
Incidents By Internal Inspections
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Internally Inspected		Inspectable Not- Inspected		Not Piggable	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	65	2.06	39	3.47	198	6.70
Internal Corrosion	2	0.06	0	0.00	12	0.41
3rd Party - Construction	16	0.51	6	0.53	42	1.42
3rd Party Farm Equipment	8	0.25	0	0.00	10	0.34
3rd Party - Train Derailment	1	0.03	1	0.09	0	0.00
3rd Party - External Corrosion	2	0.06	0	0.00	5	0.17
3rd Party - Other	8	0.25	1	0.09	5	0.17
Human Operating Error	2	0.06	2	0.18	4	0.14
Design Flaw	1	0.03	0	0.00	1	0.03
Equipment Malfunction	12	0.38	4	0.36	11	0.37
Maintenance	3	0.10	0	0.00	2	0.07
Weld Failure	11	0.35	0	0.00	8	0.27
Other	8	0.25	8	0.71	9	0.30
Total	139	4.41	61	5.42	307	10.39
Number of Mile Years	31,500		11,253		29,550	
Percentage of Total Mile Years	43.6%		15.6%		40.9%	
Total Length (Miles)	3,128		1,367		3,305	
Percentage Total Length	40.1%		17.5%		42.4%	
Mean Year Pipe Constructed	1963		1941		1944	
Mean Operating Temperature (°F)	121		148		97	
Mean Diameter (inches)	15.3		13.0		8.7	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



The data indicates that pipe which had been internally inspected had the lowest leak incident rate. However, this pipe was also the newest of any category, with a 1963 mean year of pipe construction, 6 years newer than average. This pipe was also operated at a mean operating temperature of 121°F, 23°F higher than average and had the highest mean pipe diameter, 15.3".

It is also interesting to compare the two categories of pipe which had not been internally inspected. Although the pipe which was not inspection piggable was newer and operated at a lower mean operating temperature, it had an overall incident rate almost double the rate for piggable pipe which had not been inspected. However, the mean diameter for non-piggable lines was much smaller, 8.7" versus 13.0".

4.19 Seasonal Effects

The possibility of incident rate variations throughout the year exist for many causes. For example, heavy winter rains could result in increased external corrosion leaks during the winter. Also, heavy summer construction activity could increase third party damage during this period. In an attempt to evaluate any such seasonal variations, the leak data was sorted by month of occurrence. This data is presented in Table 4-19.

Most of the leak causes appeared to have rather random variations throughout the year. Also, the limited data available for most causes made it difficult to identify any trends. However, the following points were worth noting:

- Third party damage from farm equipment did not occur from April through August during the entire 10 year study period.

- The overall leak incident rate was lowest from April through June.

4.20 Leaking Component

Table 4-20 presents a break-down of the items which leaked, by cause, for each incident included in the study. As noted, nearly 87% of all leaks occurred in the pipe body itself. Valves were responsible for another 3.1% of the incidents. 2% were caused by longitudinal weld seam failures in the pipe body. 1.6% were caused by leaks at welded fittings. The remaining 6.7% of the leaks were from various other causes.

Table 4-19
Incident Rates By Month of Year
(Incidents Per 1,000 Mile Years)

Cause of Incident	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
External Corrosion	3.65	3.49	4.98	3.15	3.15	3.82	5.64	3.15	3.65	3.49	5.97	6.31
Internal Corrosion	0.33	0.17	0.17	0.17	0.00	0.33	0.33	0.17	0.00	0.33	0.33	0.00
3rd Party - Construction	0.50	0.83	0.50	1.00	0.50	0.50	1.66	0.83	0.83	1.66	1.16	0.83
3rd Party - Farm Equipment	0.66	0.33	0.33	0.00	0.00	0.00	0.00	0.00	0.17	1.00	0.33	0.17
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.17
3rd Party - External Corr	0.00	0.00	0.17	0.17	0.00	0.17	0.00	0.17	0.00	0.17	0.17	0.17
3rd Party - Other	0.17	0.33	0.83	0.17	0.00	0.00	0.17	0.00	0.00	0.17	0.00	0.50
Human Operating Error	0.00	0.00	0.17	0.00	0.00	0.50	0.00	0.17	0.00	0.17	0.33	0.00
Design Flaw	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.17	0.00
Equipment Malfunction	0.33	0.83	0.33	0.00	0.33	0.17	0.33	1.00	0.17	0.33	0.17	0.50
Maintenance	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.17	0.17	0.17	0.17	0.00
Weld Failure	0.33	0.66	0.33	0.33	0.00	0.17	0.17	0.33	0.17	0.33	0.17	0.17
Other	0.33	0.50	0.17	0.50	0.17	0.00	0.50	0.50	0.33	0.50	0.50	0.33
Total	6.31	7.30	7.97	5.48	4.32	5.64	8.80	6.64	5.48	8.30	9.46	9.13

Incident Rates By Month of Year
Incidents Per 1,000 Mile Years

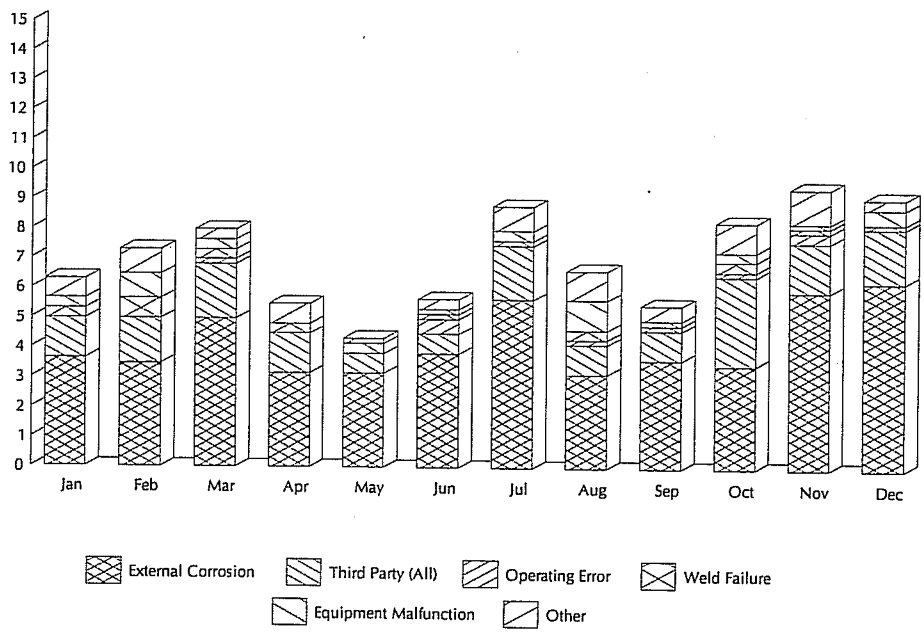
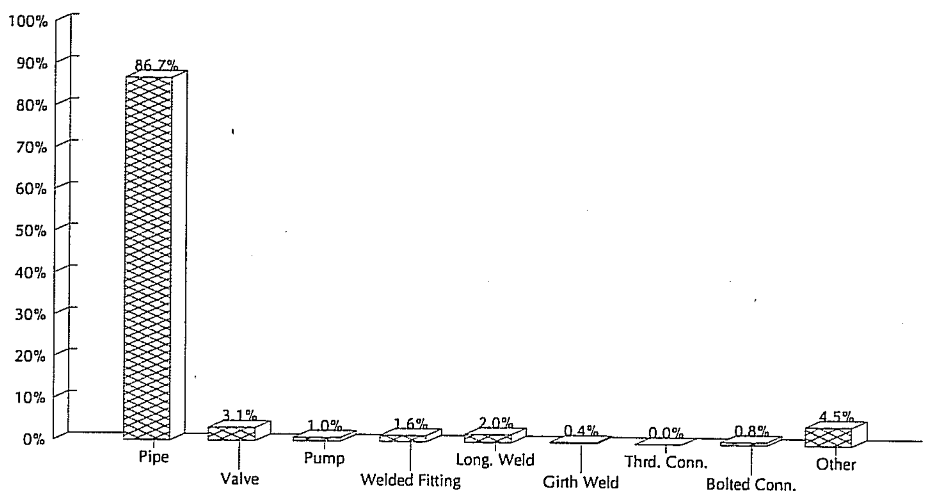


Table 4-20
Incidents by Item Which Leaked, by Cause

Leak Cause	Pipe		Valve		Pump		Welded Fitting		Long. Weld	
	No.	%	No.	%	No.	%	No.	%	No.	%
External Corrosion	298	67.3	0	0.0	0	0.0	0	0.0	0	0.0
Internal Corrosion	14	3.2	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Construction	62	14.0	2	12.5	0	0.0	1	12.5	0	0.0
3rd Party - Farm Equipment	18	4.1	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Train Derailment	2	0.5	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - External Corrosion	7	1.6	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Other	13	2.9	0	0.0	0	0.0	1	12.5	0	0.0
Human Operating Error	5	1.1	1	6.3	0	0.0	1	12.5	0	0.0
Design Flaw	0	0.0	1	6.3	0	0.0	1	12.5	0	0.0
Equipment Malfunction	6	1.4	5	31.3	2	40.0	0	0.0	1	10.0
Maintenance	1	0.2	3	18.8	0	0.0	0	0.0	0	0.0
Weld Failure	4	0.9	0	0.0	0	0.0	4	50.0	8	80.0
Other	13	2.9	4	25.0	3	60.0	0	0.0	1	10.0
Total	443	100.0	16	100.0	5	100.0	8	100.0	10	100.0

Leak Cause	Girth Weld		Thread Conn		Bolted Conn		Other	
	No.	%	No.	%	No.	%	No.	%
External Corrosion	2	100.0	0	0.0	0	0.0	4	17.4
Internal Corrosion	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Construction	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Farm Equipment	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Train Derailment	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - External Corrosion	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Other	0	0.0	0	0.0	0	0.0	0	0.0
Human Operating Error	0	0.0	0	0.0	0	0.0	1	4.3
Design Flaw	0	0.0	0	0.0	0	0.0	0	0.0
Equipment Malfunction	0	0.0	0	0.0	0	0.0	13	56.5
Maintenance	0	0.0	0	0.0	1	25.0	0	0.0
Weld Failure	0	0.0	0	0.0	0	0.0	3	13.0
Other	0	0.0	0	0.0	3	75.0	2	8.7
Total	2	100.0	0	0.0	4	100.0	23	100.0



4.21 Hydrostatic Testing Interval

The hydrostatic testing requirements for intrastate and interstate pipelines vary significantly. Basically, the regulations for intrastate lines require periodic hydrostatic testing while those for interstate lines generally require only initial hydrostatic testing. Specifically, the California Government Code §51013.5 requires hydrostatic testing of intrastate pipelines as follows:

- Every newly constructed pipeline, existing pipeline, or part of a pipeline system that has been relocated or replaced, and every pipeline that transports a hazardous liquid substance or highly volatile liquid substance, shall be tested in accordance with 49 CFR 195, Subpart E.

- Every pipeline not provided with properly sized automatic pressure relief devices or properly designed pressure limiting devices shall be hydrostatically tested annually.

- Every pipeline over 10 years of age and not provided with effective cathodic protection shall be hydrostatically tested every three years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be hydrostatically tested annually.

- Every pipeline over 10 years of age and provided with effective cathodic protection shall be hydrostatically tested every five years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be tested every two years.

- Piping within a refined products bulk loading facility shall be tested every five years for those pipelines with effective cathodic protection and every three years for those pipelines without effective cathodic protection.

For interstate pipelines, 49 CFR 195.300 requires hydrostatic testing of newly constructed pipelines; existing steel pipeline systems that are relocated, replaced, or otherwise changed; onshore steel interstate pipelines constructed before January 8, 1971, that transport highly volatile liquids; and onshore steel intrastate pipelines constructed before October 21, 1985, that transport highly volatile liquids.

Data was gathered to facilitate an evaluation of hydrostatic testing effectiveness. Two separate pieces of information were gathered. First, the total number of hydrostatic tests performed on each pipeline during the ten year study period was gathered. Secondly, for each leak which occurred during the study period, the date of the preceding hydrostatic test was obtained.

To determine the average hydrostatic test interval for each pipeline during the study period, the ten year study period was divided by the total number of hydrostatic tests performed during the study period. Incident rates were then determined for each pipeline within given ranges of hydrostatic testing intervals. Table 4-21 presents the resulting data. As indicated, the pipelines which were hydrostatically tested most frequently, up to two years average hydrostatic test interval, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase the incident rate.

On the other end of the spectrum, the lines which had the longest average hydrostatic test interval suffered the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. Once again, these factors would tend to decrease their incident rates as we have already seen.

California's *high risk* pipeline category would also tend to skew this data. As previously mentioned, these lines had a generally much higher leak incident rate. Those which were greater than 10 years old were required to be tested at either one or two year intervals, depending on whether or not they were cathodically protected.

Table 4-21A presents the second set of data; the time since hydrostatic testing for each leak, regardless of cause. Although not as drastic, this analysis resulted in similar results. As indicated, the pipelines which had the shortest interval between hydrostatic testing and the leak, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase incident rates.

On the other hand, the lines which had the greatest length of time between hydrostatic testing and the subsequent leak, had the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. These factors would decrease their incident rates as we have already seen.

With the data presented, it is difficult to readily determine the effectiveness of hydrostatic testing. The multiple regressions indicated that pipe age and operating temperatures had the greatest impact on leak incident rates. We believe that the data presented in this subsection reflected the pipe age and operating temperature effects. From this data alone, it is impossible to determine whether or not more frequent hydrostatic testing affected the frequency of leak incidents. However, the data presented in section 4-17 regarding *high risk* pipelines did not indicate a statistical relationship between more frequent hydrostatic testing intervals for *high risk* lines during the latter portion of the study period and resulting reduced incident rates. In other words, it did not appear that more frequent hydrostatic testing reduced leak incident rates. As a result, consideration should be given to increasing the hydrostatic test intervals on some frequently tested lines and redirecting these monies to work which would reduce external corrosion (e.g. internal inspection, close interval cathodic protection surveys, etc.).

Table 4-21
Average Hydrostatic Testing Interval During Study Period
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	Up to 2.0 Years		2.1 to 5.0 Years		5.1 to 10.0 Years	
	Total No.	Rate	Number	Rate	Number	Rate
External Corrosion	144	9.58	113	4.67	36	2.06
Internal Corrosion	6	0.40	6	0.25	0	0.00
3rd Party - Construction	21	1.40	15	0.62	16	0.92
3rd Party Farm Equipment	0	0.00	6	0.25	11	0.63
3rd Party - Train Derailment	0	0.00	0	0.00	1	0.06
3rd Party - External Corrosion	2	0.13	4	0.17	0	0.00
3rd Party - Other	5	0.33	2	0.08	0	0.00
Human Operating Error	5	0.33	3	0.12	0	0.00
Design Flaw	0	0.00	1	0.04	0	0.00
Equipment Malfunction	12	0.80	9	0.37	4	0.23
Maintenance	0	0.00	3	0.12	0	0.00
Weld Failure	3	0.20	10	0.41	2	0.11
Other	3	0.20	12	0.50	4	0.23
Total	201	13.37	184	7.61	74	4.24
Number of Mile Years	15,032		24,173		17,449	
Mean Year Pipe Constructed	1949		1953		1959	
Mean Operating Temperature (°F)	122.3		104.6		88.5	
Mean Diameter (Inches)	11.4		12.7		12.3	

Incident Rate Comparison

Incidents Per 1,000 Mile Years

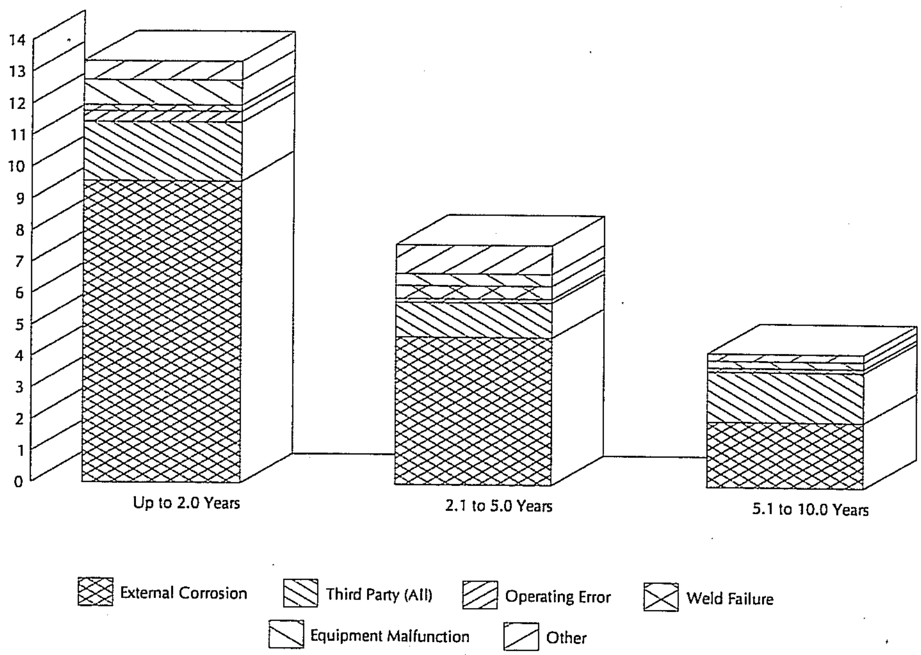
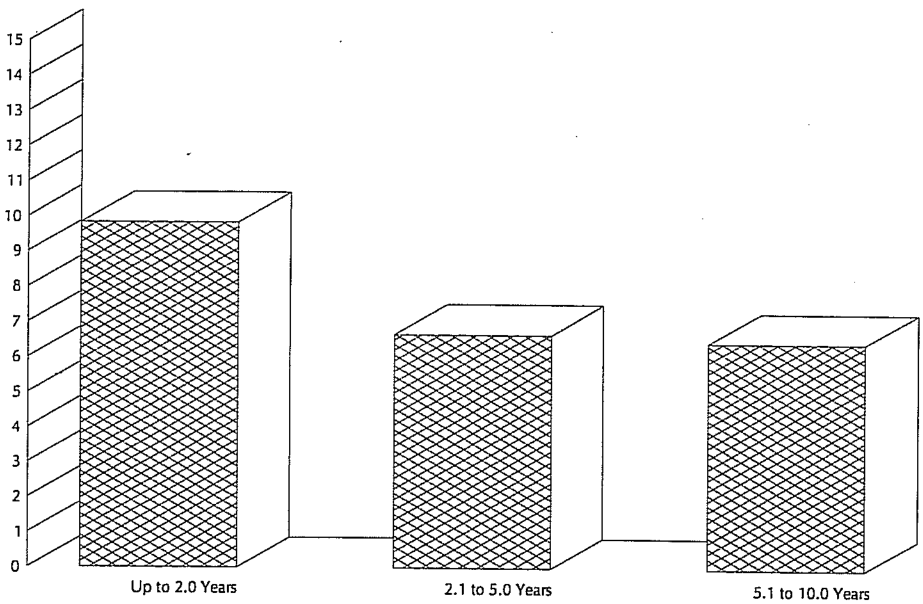


Table 4-21A
Time Since Last Hydrostatic Test At Time of Leak
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Up to 2.0 Years		2.1 to 5.0 Years		5.1 to 10.0 Years	
	Total No.	Rate	Number	Rate	Number	Rate
Total	147	9.83	165	6.67	109	6.46
Number of Mile Years	14,953		24,745		16,876	
Mean Year Pipe Constructed	1949		1953		1959	
Mean Operating Temperature (°F)	122.3		104.6		88.5	
Mean Diameter (Inches)	11.4		12.7		12.3	

Time Since Last Hydrostatic Test At Time of Leak
Incident Rate Comparison - All Causes
Incidents Per 1,000 Mile Years



Time Since Last Hydrostatic Test At Time of Leak

We also attempted to evaluate the effectiveness of hydrostatic testing by gathering data regarding the number of leaks which occurred during hydrostatic testing. Unfortunately however, the pipeline operators did not have consistent records for these leaks. Some operators had partial records for leaks which occurred during testing; but most operators did not have any records at all for these leaks. As a result, it was impossible to complete an analysis using this data.

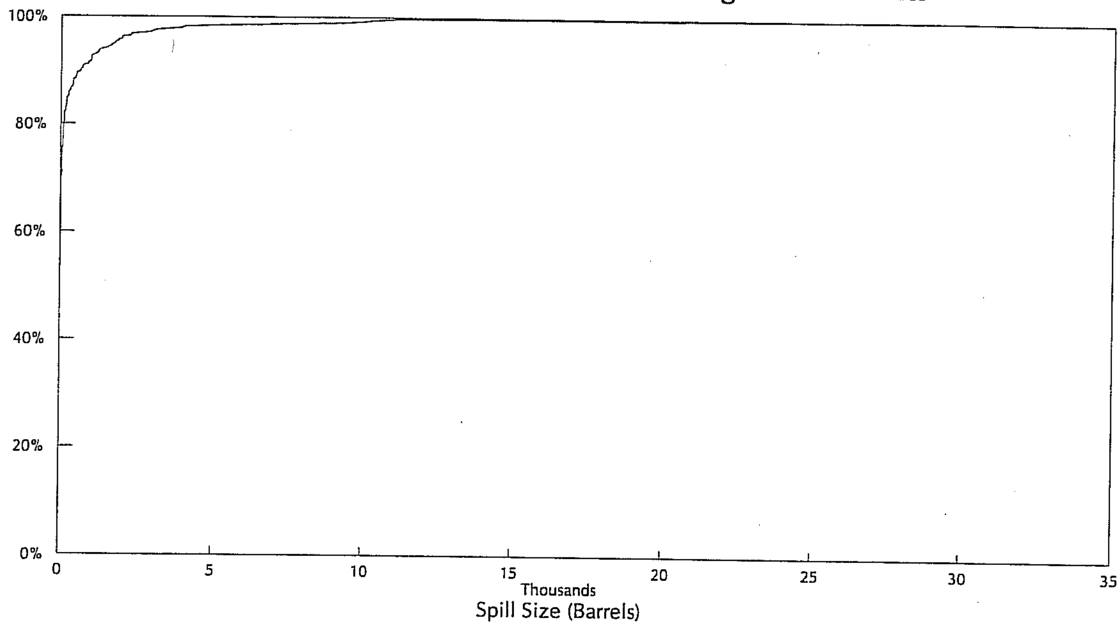
4.22 Spill Size Distribution

The spill size distribution for the leak sample is presented in Tables 4-22 and 4-22A. The coordinates of a few selected points along the curve are summarized below:

- 27% of the incidents resulted in spill volumes of one barrel or less.
- The median spill volume was five barrels.
- 61% of the incidents resulted in spill volumes of 10 barrels or less.
- 67% of the incidents resulted in spill volumes of 25 barrels or less.
- 82% of the incidents resulted in spill volumes of 100 barrels or less.
- 90% of the incidents resulted in spill volumes of 650 barrels or less.
- 95% of the incidents resulted in spill volumes of 1750 barrels or less.
- The largest spill volume was 31,000 barrels.

The huge difference between the 5 barrel median spill size and the 408 barrel mean spill size was caused by a relatively small number of incidents which resulted in large spill volumes. This increased the mean value considerably.

Table 4-22
Spill Size Distribution
Spill Size versus Cumulative Percentage of Incidents



Spill Size Distribution
Spill Size versus Cumulative Percentage of Incidents
0 to 100 Barrels Only

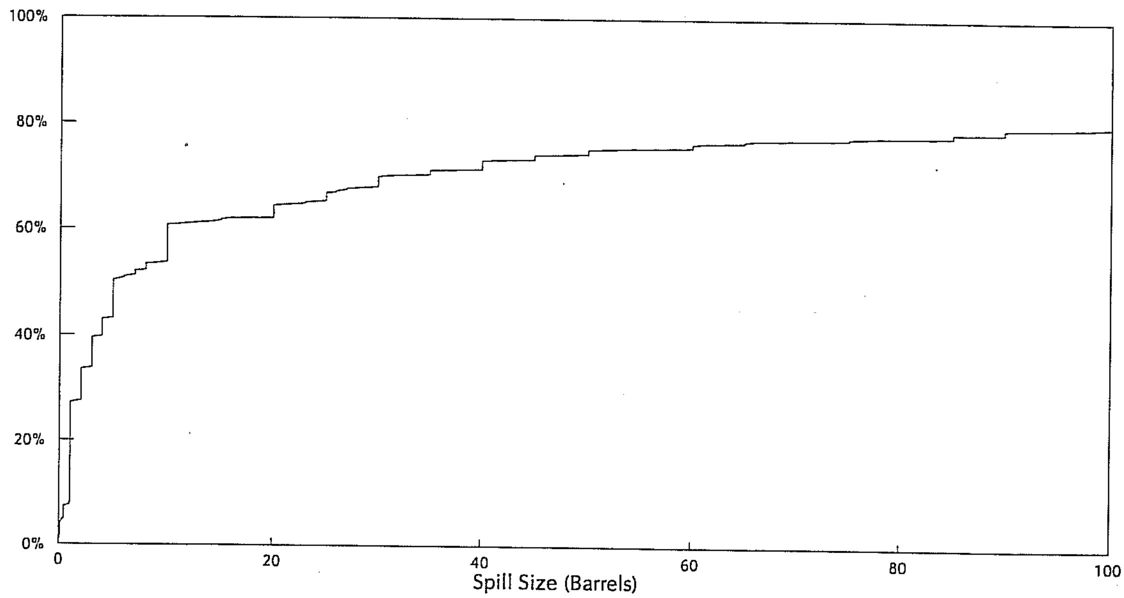
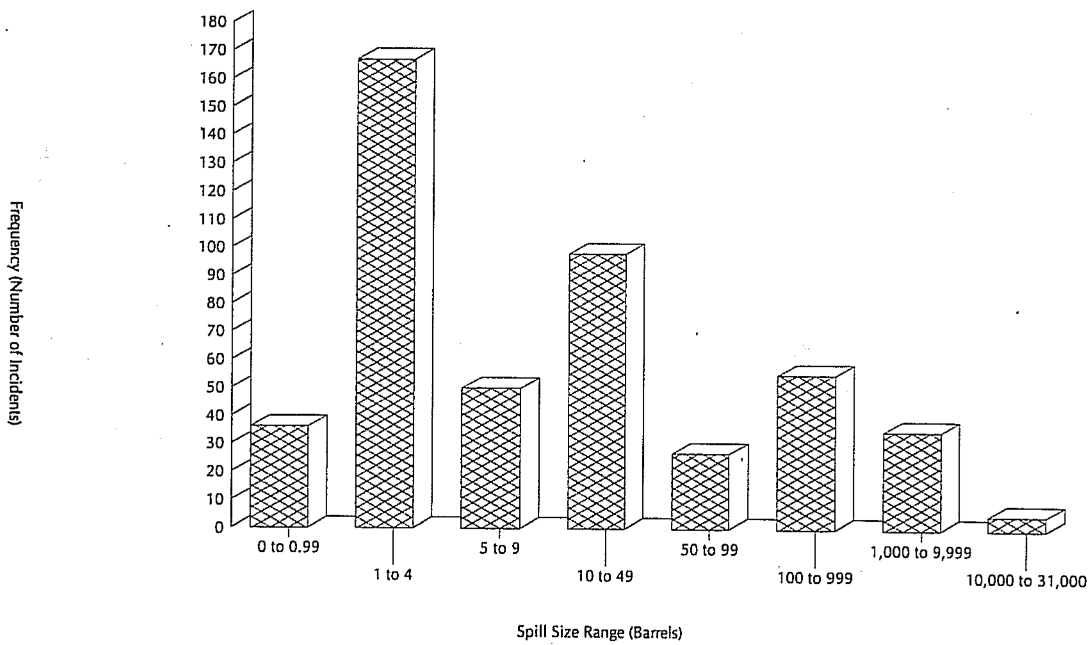


Table 4-22A
Spill Size Distribution

Spill Size (Barrels)	No. of Incidents	Percentage (%)	Cumulative %
0 to 0.99	36	7.61%	7.61%
1 to 4	167	35.31%	42.92%
5 to 9	50	10.57%	53.49%
10 to 49	98	20.72%	74.21%
50 to 99	27	5.71%	79.92%
100 to 999	55	11.63%	91.54%
1,000 to 9,999	35	7.40%	98.94%
10,000 to 31,000	5	1.06%	100.00%
Total	473		

Spill Size Distribution



4.23 Damage Distribution

The property damage distribution was very similar to the spill size distribution discussed in the preceding section; a few incidents resulted in relatively large property damage values which increased the mean value considerably. To the greatest extent possible, the damage figures included in this study included all costs associated with the incident (e.g. value of spilled fluid, clean-up, injury, judgements, fatalities, etc.).

Table 4-23 depicts this data graphically. All data has been shown in constant 1983 U.S. dollars. The values for each year were converted to 1983 constant dollars using the U.S. City average Consumer Price Indices as published by the U.S. Bureau of Labor Statistics. A few points along the curve are presented below:

- 25% of the incidents resulted in damages of $1,300 or less.
- The median damage was $7,200 per incident.
- 75% of the incidents resulted in damages of $38,000 or less.
- 90% of the incidents resulted in damages of $180,000 or less.
- 95% of the incidents resulted in damages of $590,000 or less.
- The largest reported damage for a single incident was $11,800,000. However, we understand that this figure may increase as additional claims are settled.

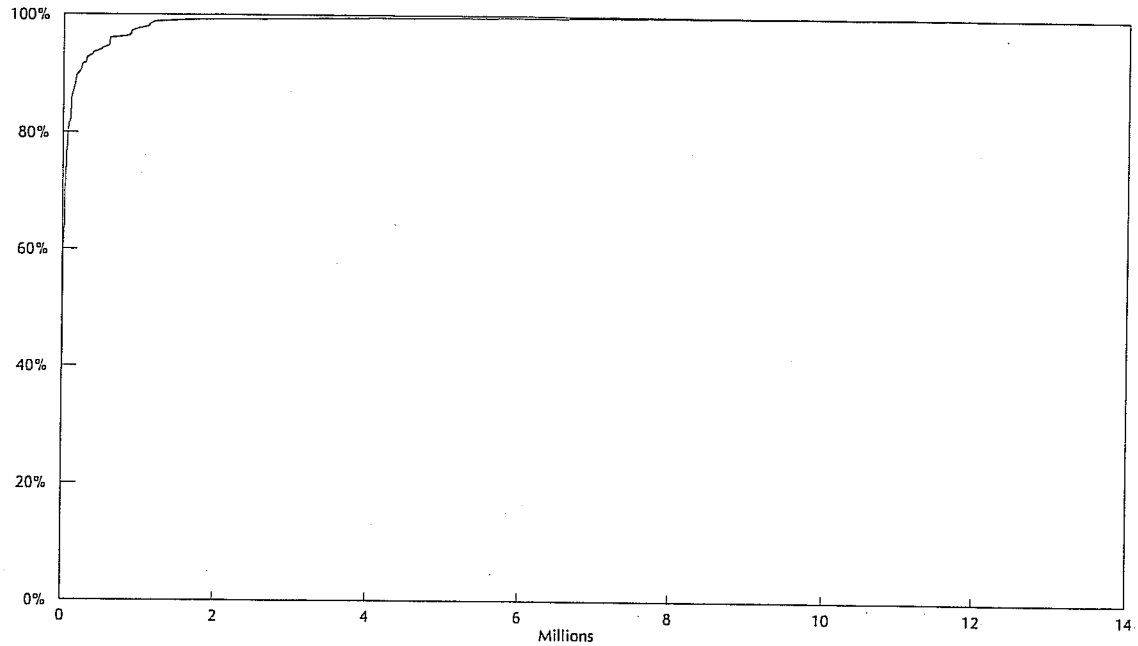
4.24 Stress Level Distribution

On 339 out of the total 514 leaks, sufficient data was available to calculate the stress level of the pipe at the leak site. The stress level, as a percentage of the pipe specified minimum yield strength, was determined using the following equation:

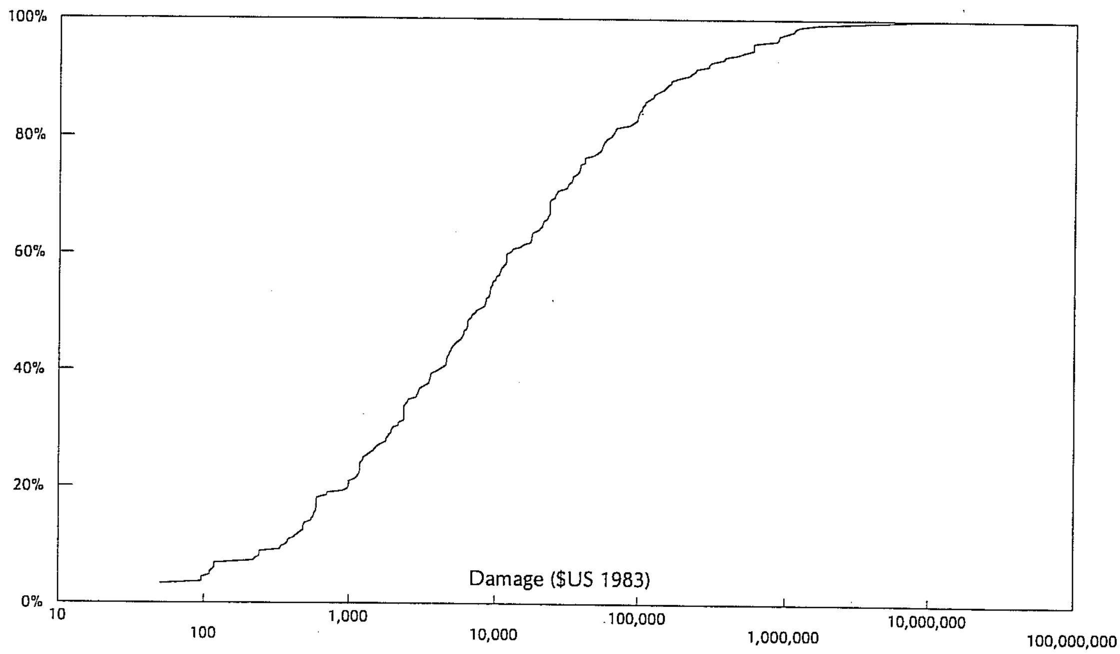
$$\% \text{ SMYS} = \{(P * D) \div (2 * t)\} \div \text{SMYS}$$

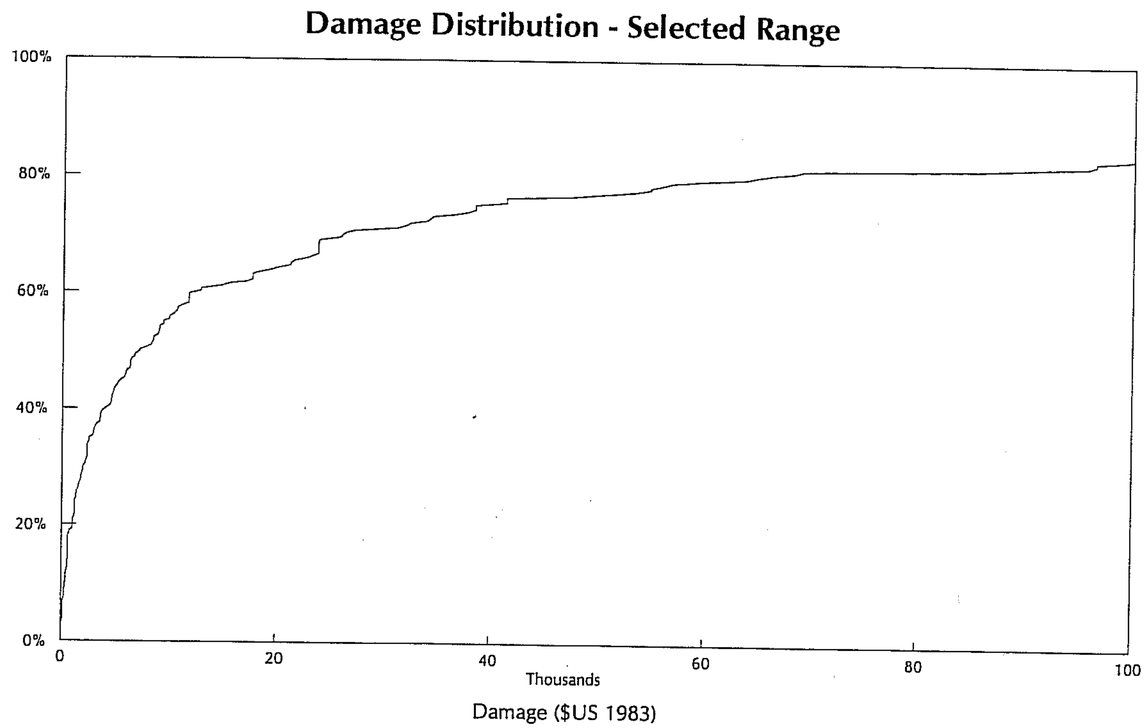
where: P = normal operating pressure (pounds per square inch)
D = outside pipe diameter (inches)
t = pipe wall thickness (inches)
SMYS = specified minimum yield strength of pipe which suffered the leak incident (psi)

Table 4-23
Damage Distribution
Includes All Leaks With Property Damage Data



Damage Distribution - Logarithmic Scale




Damage Distribution - Selected Range
100%
80%
60%
40%
20%
0%
0
20
40
60
80
100
Thousands
Damage ($US 1983)

The cumulative percentage of the total leaks has been plotted versus the operating stress level in Table 2-24. As indicated, the median value for these leaks was relatively low, 24% SMYS. Also, from the shape of the curve we can see that the steepest portion occurred at the lower stress levels. The curve then flattened as the stress level increased.

However, one should be cautious about drawing conclusions from this data. Since some pipelines had literally thousands of pipe sections, all operating at different stress levels, it was impossible to develop an inventory of pipe operating at each stress level. Without this inventory, it was impossible to develop meaningful incident rates, as developed for other parameters. However, although not necessarily directly related, we did find in Section 4-15 that there was not a correlation between operating pressure and leak incident rates.

4.25 Injuries and Fatalities

The number of injuries and fatalities which resulted from incidents on California's regulated hazardous liquid pipeline systems during the study period are presented in Tables 4-25 and 4-25A. As indicated, nearly 94% of the injuries and all of the fatalities resulted from only three incidents; it is remarkable that just over one-half percent of the total incidents resulted in all of the fatalities and nearly all of the injuries during the entire ten year study period. These incidents are briefly described below:

- May 25, 1989, San Bernardino - On May 12, 1989, a freight train derailed in San Bernardino, California. On May 25, 1989, 13 days later, a regulated interstate petroleum products pipeline ruptured. The National Transportation Safety Board determined that during the derailment, and later during the movement of heavy equipment to remove the wreckage, the high-pressured products pipeline adjacent to the tracks was damaged and weakened. Less than two weeks after the wreck, the pipeline ruptured and spilled over 300,000 gallons of gasoline into the neighborhood. The spilled fluid ignited and caused significant fire damage. This incident resulted in two fatalities and thirty-one injuries.

- February 22, 1986, Placer County - During the removal of an abandoned section of pipeline which had been relocated around a collapsed railroad trestle, approximately one barrel of gasoline was spilled. The fuel was ignited by a torch being used by the railroad's welding crew. As a result of the ignition, three welders jumped from the bridge into the creek below. This incident resulted in one fatality and one injury.

Table 4-24
Stress Level Distribution
At Incident Location

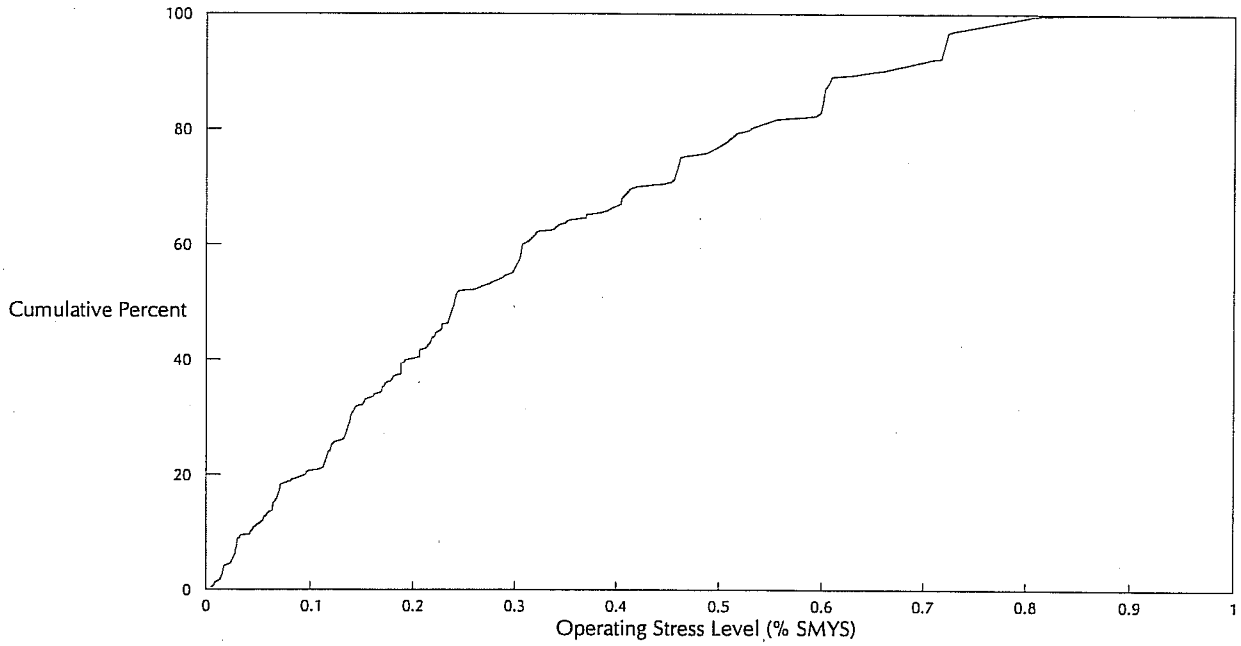
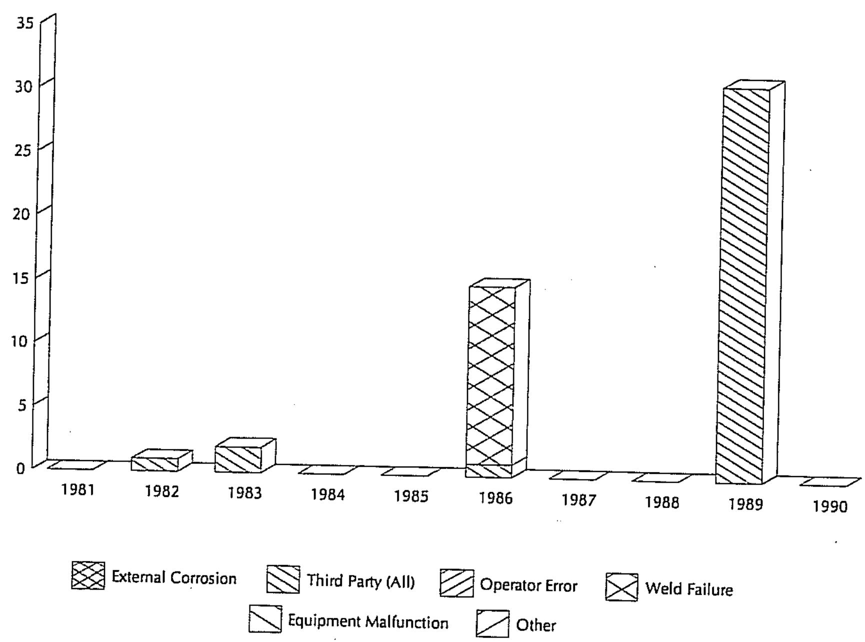


Table 4-25
Injuries By Year Of Study - By Cause
(Incidents Per 1,000 Mile Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	Total
External Corrosion	0	0	0	0	0	0	0	0	0	0	0
Internal Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Construction	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Farm Equipment	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Train Derailment	0	0	0	0	0	0	0	0	31	0	31
3rd Party - External Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Other	0	1	2	0	0	1	0	0	0	0	4
Human Operating Error	0	0	0	0	0	0	0	0	0	0	0
Design Flaw	0	0	0	0	0	0	0	0	0	0	0
Equipment Malfunction	0	0	0	0	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0	0	0	0	0
Weld Failure	0	0	0	0	0	14	0	0	0	0	14
Other	0	0	0	0	0	0	0	0	0	0	0
Total	0	1	2	0	0	15	0	0	31	0	49

Injuries By Year of Study

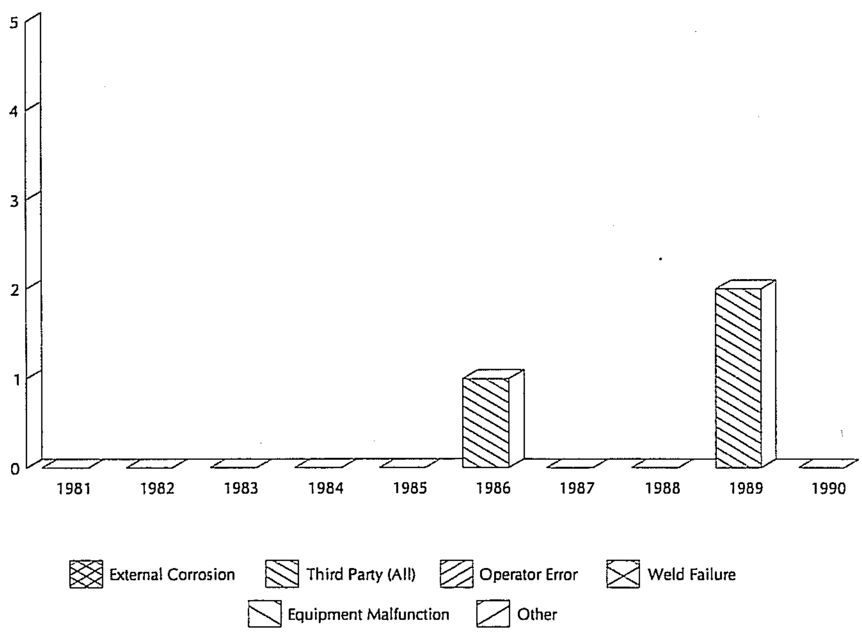


Note: The injury data presented above includes all injuries, regardless of severity; in some cases, incidents which only envolved on-site treatment are included. The reader should be cautioned from drawing any potentially misleading conclusions when comparing this data to that available from other sources.

Table 4-25A
Fatalities By Year Of Study - By Cause
(Incidents Per 1,000 Mile Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	Total
External Corrosion	0	0	0	0	0	0	0	0	0	0	0
Internal Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Construction	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Farm Equipment	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Train Derailment	0	0	0	0	0	0	0	0	2	0	2
3rd Party - External Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Other	0	0	0	0	0	1	0	0	0	0	1
Human Operating Error	0	0	0	0	0	0	0	0	0	0	0
Design Flaw	0	0	0	0	0	0	0	0	0	0	0
Equipment Malfunction	0	0	0	0	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0	0	0	0	0
Weld Failure	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	1	0	0	2	0	3

Fatalities By Year of Study



- November 22, 1986, Tustin - A 10" API 5L X52, ERW pipe longitudinal weld seam ruptured. This resulted in a roughly 11,000 barrel unleaded gasoline spill. Fortunately, the spill did not result in fire or an explosion. The DOT Form 7000-1 filed with the Department of Transportation indicated that there were no injuries or fatalities meeting their reporting criteria. (See also Section 3.0 of this report.) However, 14 individuals were treated for symptoms consistent with hydrocarbon exposure. Eight fire personnel were treated at a medical facility, four fire personnel and one civilian were treated and released at the scene, and one fire department equipment operator was hospitalized for observation. These were treated as 14 injuries for the purposes of this study.

It is interesting to note that each of these spills had a different cause. Two were caused by some form of third party damage, while the third was caused by a material defect.

The number of incidents resulting in injuries and fatalities was too small to draw any meaningful conclusions. However, it should be noted that all injuries and fatalities occurred on petroleum product pipelines; crude line incidents did not result in any injuries or fatalities during the study period.

The present regulations are basically the same for product and crude pipelines. However, although a limited sample, this data indicated that the risks to human life were likely greater for product pipelines. As a result, there may be justification for having some differences between crude and product pipeline regulations. On the other hand, both crude and product pipeline incidents resulted in similar environmental concerns.

As mentioned previously, *all* injuries, regardless of severity, were included in these data. For instance, the 1986 Tustin incident resulted in 14 injuries which did not meet the Department of Transportation injury reporting criteria. Deleting these injuries alone would have reduced the resulting injury rate for this study by more than one-third. The reader must keep the injury criteria used in this study in mind; otherwise, the public injury risk may be over-exaggerated. Unfortunately, sufficient data was not available to sort the injuries incurred during the study period by severity.

4.26 Multiple Regression Analyses

As mentioned briefly in preceding sections, multinomial logit regressions were performed. These analyses predicted the probability of a pipeline rupture considering selected variables. The variables used were those that appeared to influence the incident rates observed in previous analyses, provided data was available to perform the analyses.

The first regressions included the following variables:

- total pipeline length,
- year of pipe construction,
- normal operating temperature,
- normal operating pressure,
- normal operating flow rate,
- length within 500 feet of a rail line,
- length of inspection piggable pipeline,
- dummy variable indicating interstate or intrastate pipeline, and
- dummy variable indicating common carrier or non-common carrier pipeline.

A polytimous dependent variable was used with three outcomes possible: 0) no leak; 1) leak due to external corrosion; and 2) leak due to other causes. For purposes of comparison, two models were used in the analyses. The first, was a logit regression which used a dependent variable with all leaks combined. The second was a multinomial logit regression using the polytimous dependent variable that breaks down ruptures by cause. The second model was defined as such because the majority of the leaks were caused by external corrosion. As a result, the factors affecting the external corrosion leaks may have been different than those affecting leaks caused by other sources. The regression used outcome 0, no leak, as the point of departure. The probability of outcome 1 or 2, or both combined, was predicted, therefore, relative to the probability of outcome 0.

From the coefficients and significance levels provided, we observed that the probability of a leak due to external corrosion was differentially affected by the independent variables in comparison to the probability of a leak due to other causes. Thus the polytimous logit model was better suited to predict the probability of a leak.

The probability of a leak occurring due to external corrosion was affected positively by normal operating temperature and total length of pipeline. These correlations were statistically significant at the 0.000 level. The year of pipe construction was inversely related to the probability of a leak and was also highly significant at the 0.002 level. Specifically, as pipe age increased, as normal operating temperature increased and the total pipeline length increased, external corrosion leaks were more probable holding all else constant. Operating pressure and proximity to a rail line showed no statistical relationship to the probability of a leak due to external corrosion.

In contrast, the relationship between normal operating temperature and the probability of a leak occurring due to causes other than external corrosion was not statistically significant. Coincidentally, increased normal operating flow raised the probability of a leak occurring from other causes, while not affecting external corrosion leaks. Additionally, common carrier status increased the probability of a leak from other causes, but did not affect the probability of an external corrosion incident. Year of construction had the greatest effect on the probability of all leaks. The total length of pipeline was directly and significantly related to the probability of a leak occurring. There was no statistical relationship between the length of line near a rail line and the probability of an incident from any cause.

5.0 Seismic Activity Effect

Large earthquakes in populated areas often cause damage to buried pipelines. For example, the recent June 28, 1992 Richter magnitude 7.4 earthquake in the Landers/Yucca Valley area of southern California resulted in an estimated 700 breaks to water system pipelines. In general, seismic damage to buried pipelines is due to some combination of seismic wave propagation and permanent ground displacement.

Wave propagation refers to *out-of-phase* motion of a buried pipeline as seismic waves travel along the ground surface. That is, at one point in time during the shaking, one portion of a pipeline may be moving in one direction, while another portion of the line may be moving in another. Wave propagation occurs only during the ground shaking associated with a seismic event.

Permanent ground deformation refers to seismic activity which results in a permanent change to the ground profile. The four types of permanent ground deformation include:

- fault movement,
- liquefaction and subsequent lateral spreading,
- landslides, and
- subsidence.

In California, fault movement at the ground surface is usually some combination of vertical offset (the ground on one side of the fault appears to have moved upwards with respect to the ground surface on the other side of the fault) and horizontal offset (the ground on one side of the fault appears to have moved to the right or to the left with respect to the ground on the other side of the fault). For example, the 1992 Landers event resulted in roughly 1'- 6" of vertical offset and over 7'- 0" of right lateral horizontal offset near Old Woman Springs Road (State Highway 247); this movement damaged the 8 inch diameter asbestos cement water pipeline which crossed the fault.

Strong shaking of saturated sand can cause the soil to liquify. This situation is called liquefaction. Lateral spreading refers to the movement of the liquified soil mass down slope or towards a free face such as a river bank. As with fault movement, lateral spreading and landslides result in a permanent change to the soil profile.

Seismic subsidence refers to downward movements of the ground surface due to densification of subsurface soils caused by strong shaking. For example one can view dry soil as a collection of hard particles of various sizes. Like marbles in a box, the spaces between the particles are occupied by air. When shaken laterally back and forth, the particles will rearrange themselves so that some of the smaller particles move into the spaces between the bigger particles, resulting in a denser packing of the particles. This can result in a downward movement of the top surface.

As noted earlier, seismic ground movements often cause damage to buried pipelines. However, in discussing pipe damage, one must distinguish between damage to segmented versus continuous pipelines. Various earthquakes have shown that damage to segmented pipelines (e.g. bell and spigot, flange, etc. joined cast iron or asbestos cement) is much more common than damage to continuous pipelines (e.g. full penetration welded steel).

For segmented lines, damage occurs most often at the joints, particularly for larger diameters. Typical damage mechanisms include:

- joint *pull-out* (axial extension),
- joint *crushing* (axial compression), and
- joint *bending* (angular rotation).

For modern, full penetration arc-welded pipe made of high grade steels, seismic damage is usually comprised of circumferential tearing of the pipe wall. This is caused by local buckling (the pipe in compression deforms somewhat like an *accordion*). In addition, small diameter *pin hole* leaks often occur at areas previously weakened by corrosion or prior repairs.

In this section, we will develop an estimate of expected seismic damage to California's regulated hazardous liquid pipelines. This estimate will be based upon an analysis of observed seismic damage during the study period as follows:

- The observed damage will be characterized by a plot of incidents per kilometer of pipe versus the modified Mercali Intensity (MMI) for various seismic events.

- This graph will then be combined with postulated California seismic activity for a 30 year period. The postulated activity will be based on observed seismic activity in California from 1850 through 1989 (139 years). The observed seismic activity will be characterized by a plot giving the annual probability of occurrence of various magnitude earthquakes.

- Knowing the probability of a pipe rupture for a given seismic event and the probability of such an event occurring, one can develop an estimate of the number of anticipated incidents. However, both the density of pipelines and the severity of seismic ground motion are location dependent. As a result, three scenarios will be evaluated to bracket the probable range of results.

5.1 Observed Damage

Of the roughly 500 leak incidents on California's regulated hazardous liquid pipelines during the study period, only 3 were judged to be due directly to earthquake effects.

These three leaks are summarized below. The summaries include information on the causative earthquake, its Richter magnitude, and the Modified Mercali Intensity (MMI).

The modified Mercali intensity is a subjective measure of the earthquake effects at various locations for a given event. There are a number of MMI's for an individual event. Close to the epicenter, the MMI is relatively high; as the distance from the epicenter increases, the MMI decreases, reflecting the reduction in ground shaking at these locations. On the other hand, there is only one Richter Magnitude (M) per earthquake; it is a measure of ground shaking at the epicenter.

- Leak Number 1 - On October 26, 1982, a leak in a 20" diameter, 0.250" wall thickness pipeline was reported in Fresno County. The leak was due to a crack along the lower edge of a side strap on the X-52 grade steel pipeline. The repair report notes that the opposite side of the pipe had a leak in June 1982.

  Map coordinates place the leak location about 30 miles north/northwest of the epicenter of a relatively small (local magnitude $M_L \approx 5.5$) earthquake which occurred the day before near Coalinga. The maximum MMI for this event was VI (U.S. Geological Survey Bulletin 1655). There were no recorded MMI values for the relatively sparsely populated area between the epicenter and the leak location. As a result, we have assumed that the MMI for the nearby leak site was VI.

- Leak Number 2 - On March 8, 1984, a leak in a 20" diameter, 0.250" wall thickness pipeline was reported in Fresno County. The leak was due to tearing of the pipe wall due to circumferential compression buckling or wrinkling of the X-52 grade steel pipeline.

  Map coordinates place the leak location within the area of MMI zone VIII for the May 2, 1983 Coalinga earthquake ($M_L \approx 6.3$) earthquake. Although the leak was discovered about 10 months after the earthquake, the leak description suggests that the pipe damage was likely caused by the earthquake.

- Leak Number 3 - On October 17, 1989, a leak in a 6" diameter, 0.281" wall thickness pipeline in Marin County was reported. The leak was due to cracking of a weld at a pipe bend. Map coordinates place the leak location at the boundary of an area of MMI VII for the Loma Prieta earthquake ($M_L \approx 7.0$) which occurred the day of the leak (U.S. Geological Survey Open File Report 90-18).

A summary of the data available for these three leaks is presented in Table 5-1. Fortunately, the three seismic leaks were distributed among areas with Modified Mercali Intensities of VI, VII and VIII; otherwise, the development of probable seismic incident rates may have been impossible.

5.2 Observed Leak Rate

In this section, the observed seismic damage will be characterized in terms of incidents per kilometer (km) of pipe (1.6 km = 1 mile), for various seismic events. The relative ground shaking caused by an event will be quantified using the Modified Mercali Intensity (MMI) as described earlier. Unfortunately, the small number of seismic leaks precludes a more detailed breakdown by damage mechanism (e.g. leaks per kilometer from wave propagation, leaks per kilometer from subsidence, etc.).

The earthquakes considered were taken from a table of major California and Nevada earthquakes from 1769 to 1989 (U.S. Geological Survey Professional Paper 1515). In that listing there were 17 California earthquakes for the time period from January 1, 1981 through December 31, 1990.

The observed leak rate was determined by first obtaining the total length of pipe exposed to various MMI levels for each earthquake during the study period. Then, the observed number of incidents per MMI zone, was divided by the total length of pipe exposed to corresponding MMI levels to yield the observed incident rate.

More specifically, the approximate length of pipe in the various MMI zones was determined for each of the 17 earthquakes as follows:

- The various MMI zone areas were measured for each earthquake. This was accomplished using isoseismal maps available from the U.S. Geological Survey. (See Table 5-2.)

- The length of pipe within each County was then determined. The length of each line was measured with a planimeter, using the California State Fire Marshal's roughly 1,700 Thomas Guide map book overlays and other pipeline maps available from the pipeline operators.

- The density of pipe (pipe length per unit of land area) for each County was then determined by dividing the total length of line within each County, by the area of the County itself. (See Table 5-2A.)

Table 5-1
Seismic Leak Summary
California Regulated Hazardous Liquid Pipelines
Study Period - January 1, 1981 through January 31, 1990

Leak No.	Pipe Information: Diameter (inches)	Wall Thick (inches)	Grade	Cover (inches)	Earthquake Information: Date	MMI Epicenter	MMI Leak Site	Description
1	20"	0.250"	X-52	144"	October 25, 1982	VI	VI (?)	Leak along the lower edge of side strap, opposite side of pipe repaired in June 1982.
2	20"	0.250"	X-52	180"	May 2, 1983	VIII	VIII	Pipe wall tearing due to circumferential buckling.
3	6"	0.281"	N/A	54"	October 17, 1989	IX	VII	Craking of weld at pipe bend.

Table 5-2
Seismic Event Summary
California Regulated Hazardous Liquid Pipelines

Study Period - January 1, 1981 through December 31, 1990

Earthquake Number	Date of Occurrence	County Name	Local Magnitude	Affected Area (square kilometers)		
				MMI VI	MMI VII	MMI VIII
1	April 26, 1981	Imperial	5.6	1,628	625	-
2	September 4, 1981	Offshore	5.3	294	-	-
3	September 30, 1981	Mono	5.9	*	*	*
4	May 2, 1983	Fresno	6.3	9,375	2,294	625
5	July 22, 1983	Fresno	5.8	1,800	-	-
6	April 24, 1984	Santa Clara	6.2	3,000	300	-
7	September 10, 1984	Humboldt	6.6	-	-	-
8	November 23, 1984	Inyo	6.1	-	-	-
9	August 4, 1985	Fresno	5.6	750	-	-
10	July 8, 1986	San Bernardino	5.9	8,500	589	69
11	July 20, 1986	Mono	5.9	*	*	*
12	July 21, 1986	Mono	6.2	*	*	*
13	July 31, 1986	Mono	5.8	*	*	*
14	October 1, 1987	Los Angeles	5.9	2,496	704	24
15	November 24, 1987	Imperial	5.8	*	*	*
16	November 24, 1987	Imperial	6.0	*	*	*
17	October 18, 1989	Santa Cruz	7.0	21,224	6,000	533

* indicates that affected area was not calculated since no regulated hazardous liquid pipe was precent in the epicenter County.

Table 5-2A
Pipe Density By County
California Regulated Hazardous Liquid Pipelines
Study Period - January 1, 1981 through December 31, 1990

County Name	County Area (square kilometers)	Pipeline Length (kilometers)	Pipe Density (kilometers/square kilometer)
Alameda	1,905	279	0.146
Butte	4,261	46	0.011
Contra Costa	1,890	812	0.430
Fresno	15,476	580	0.037
Humboldt	9,266	2	<0.001
Kern	21,048	1,696	0.081
Kings	3,603	253	0.070
Los Angeles	10,537	3,198	0.304
Madera	5,553	54	0.010
Marin	1,354	<1	<0.001
Merced	5,033	295	0.059
Monterey	8,551	2	<0.001
Nevada	2,485	35	0.014
Orange	2,065	524	0.254
Placer	3,666	174	0.047
Riverside	18,676	520	0.028
Sacramento	2,513	147	0.058
San Bernardino	51,943	1,379	0.027
San Diego	10,910	575	0.053
San Francisco	119	2	0.019
San Joaquin	3,663	253	0.069
San Luis Obispo	8,564	761	0.089
San Mateo	1,157	44	0.038
Santa Barbara	7,114	206	0.029
Santa Clara	3,347	28	0.008
Sierra	2,483	24	0.010
Solano	2,159	148	0.068
Stanislaus	3,899	204	0.052
Sutter	1,559	17	0.011
Tulare	12,447	27	0.002
Ventura	4,820	363	0.075
Yolo	2,625	47	0.018
Yuba	1,563	35	0.022

- An estimate of the pipe length affected by a given event was then determined by multiplying the MMI zone area by the pipe density for the county in which the epicenter was located. For the 17 earthquakes during our study period, this resulted in the values shown below. (See also Table 5-2B.)

MMI Zone VI	1,600 kilometers of pipe
MMI Zone VII	412 kilometers of pipe
MMI Zone VIII	45 kilometers of pipe

- The observed incident rate for each MMI value was then determined by dividing the number of incidents, one each for MMI zones VI, VII and VIII, by the estimated pipe lengths for each zone (values shown above). This resulted in the following incident rates:

MMI Zone VI	0.00063 incidents per km of pipe
MMI Zone VII	0.0024 incidents per km of pipe
MMI Zone VIII	0.022 incidents per km of pipe

This methodology distinguishes between earthquakes in, for example, Imperial, Inyo or Mono counties, where there are no regulated hazardous liquid pipelines (pipe density is equal to zero), from earthquakes in Los Angeles County, where the pipe density is 0.30 kilometers of pipe per square kilometer of land area.

It is interesting to note that the average pipe density for the entire state is approximately 0.032 kilometers of pipe per square kilometer of land area (roughly 12,900 kilometers of regulated hazardous liquid pipeline over a total land area of 405,000 square kilometers). It is also interesting that the pipe densities vary widely; Los Angeles County for example has a pipe density nearly ten times the state average. (See also Table 5-2A presented earlier.)

The three incident rate data points are plotted semi-logarithmically versus MMI zone in Table 5-2C. An ordinary least squares line of best fit was prepared using the logarithm of the actual incident values; it yielded a very high *R squared* of 0.9800. (*R squared* values range from zero to one. They can be interpreted as the proportion of the variation in a given sample which is explained by the resulting regression equation; they are a comparison of the estimated systematic model with the mean of the observed values.) By extrapolation, one may expect about 0.11 incidents per kilometer of pipe for MMI zone IX areas. Once again, it should be noted that this data includes seismic damage due to all causes, *both wave propagation and permanent ground deformation.*

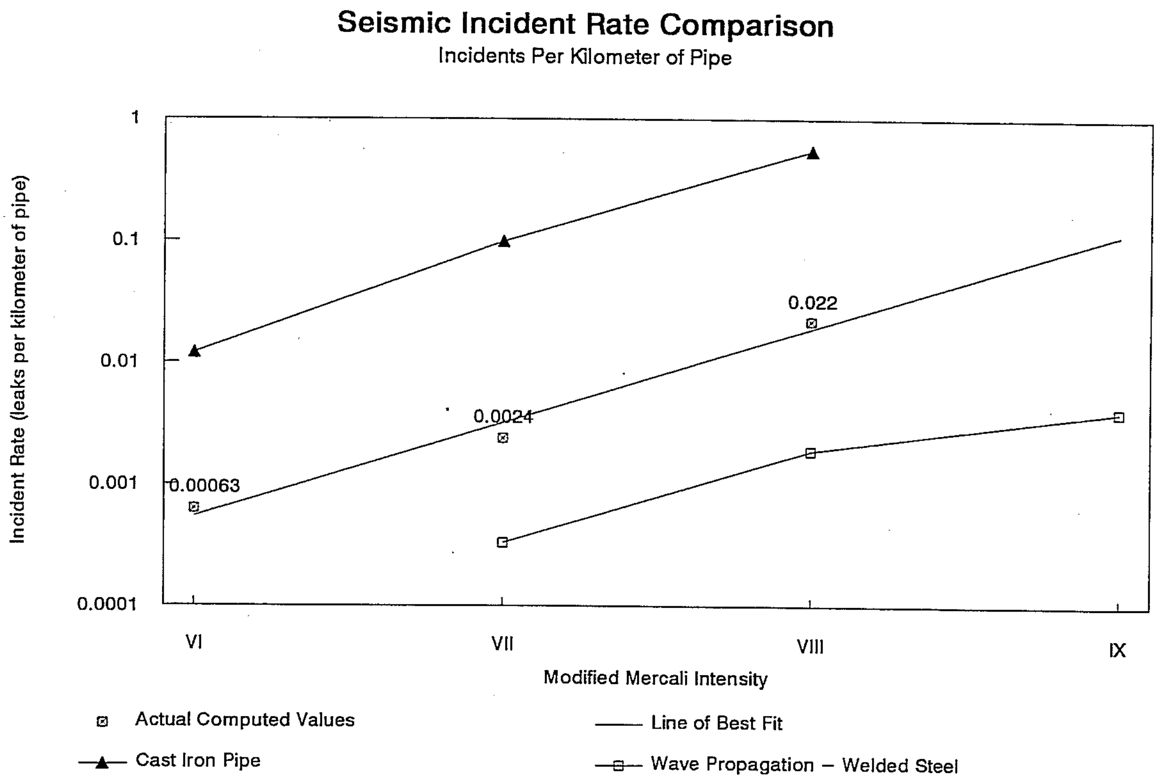
Table 5-2B
Estimated Pipe Lengths Exposed to Various MMI
California Regulated Hazardous Liquid Pipelines
Study Period - January 1, 1981 through December 31, 1990

Earthquake Number	County Name	Epicenter Pipe Density (km/km²)	Estimated Pipe Length (kilometer)		
			MMI VI+	MMI VII+	MMI VIII+
1	Imperial	0.000	-	-	-
2	Offshore	0.304	89.2	-	-
3	Mono	0.000	-	-	-
4	Fresno	0.037	350	85.5	23.3
5	Fresno	0.037	67.1	-	-
6	Santa Clara	0.008	26.1	2.61	-
7	Humboldt	<0.001	-	-	-
8	Inyo	0.000	-	-	-
9	Fresno	0.054[1]	40.3	-	-
10	San Bernardino	0.027	227	15.7	1.8
11	Mono	0.000	-	-	-
12	Mono	0.000	-	-	-
13	Mono	0.000	-	-	-
14	Los Angeles	0.304	757	213	7.3
15	Imperial	0.000	-	-	-
16	Imperial	0.000	-	-	-
17	Santa Cruz	0.023[2]	495	140	12.4
		Totals[3]	2,051.7	456.8	44.8

[1] The epicenter was located at the Fresno and Kings County border. The average pipe density for these counties was used.
[2] MMI VII was recorded in both Santa Clara and San Mateo Counties. The average pipe density for these counties was used.
[3] To determine the length within each individual MMI zone, the length within the next group of zones must be subtracted. For example, the length of pipe in MMI = VI is 2,051.7 - 456.8 = 1,594.9.

Table 5–2C
Seismic Incident Rates
California Regulated Hazardous Liquid Pipelines
Study Period – January 1, 1981 through December 31, 1990

Modified Mercali Intensity	Actual Incident Rate (incidents per kilometer of pipe)	Straight Line Fit (incidents per kilometer of pipe)
VI	0.00063	0.00054
VII	0.0024	0.0032
VIII	0.022	0.019
IX	N/A	0.11



Two other relations are also shown in Figure 5-2C. The upper relation (O'Rourke et al) is for seismic damage to cast iron pipe due to all causes (wave propagation and permanent ground deformation). The lower relation (Eguchi) is for seismic damage to steel pipe with arc-welded joints due to wave propagation only. Hence the seismic leak rate developed herein is reasonable, since it falls within the expected range. That is, the incident rate for all causes for regulated California hazardous liquid pipelines is less than that for segmented cast iron pipe. Similarly, the incident rate for regulated California hazardous liquid pipelines due to all causes is greater than that for wave propagation damage only to welded steel pipe.

5.3 Future Seismic Activity

The expected seismic activity in California for a future 30 year period has been based herein on observed earthquakes in California from 1850 through 1989. In other words, we have assumed that the underlying rate of earthquake occurrence will not change. The U. S. Geological Survey's listing of major California and Nevada earthquakes, 1769-1989 (U.S. Geological Survey Profession Paper 1515 mentioned previously), was used to identify California earthquakes during the selected 130 year period. Activity prior to 1850 was excluded since some quakes may have been missed due to the sparse population.

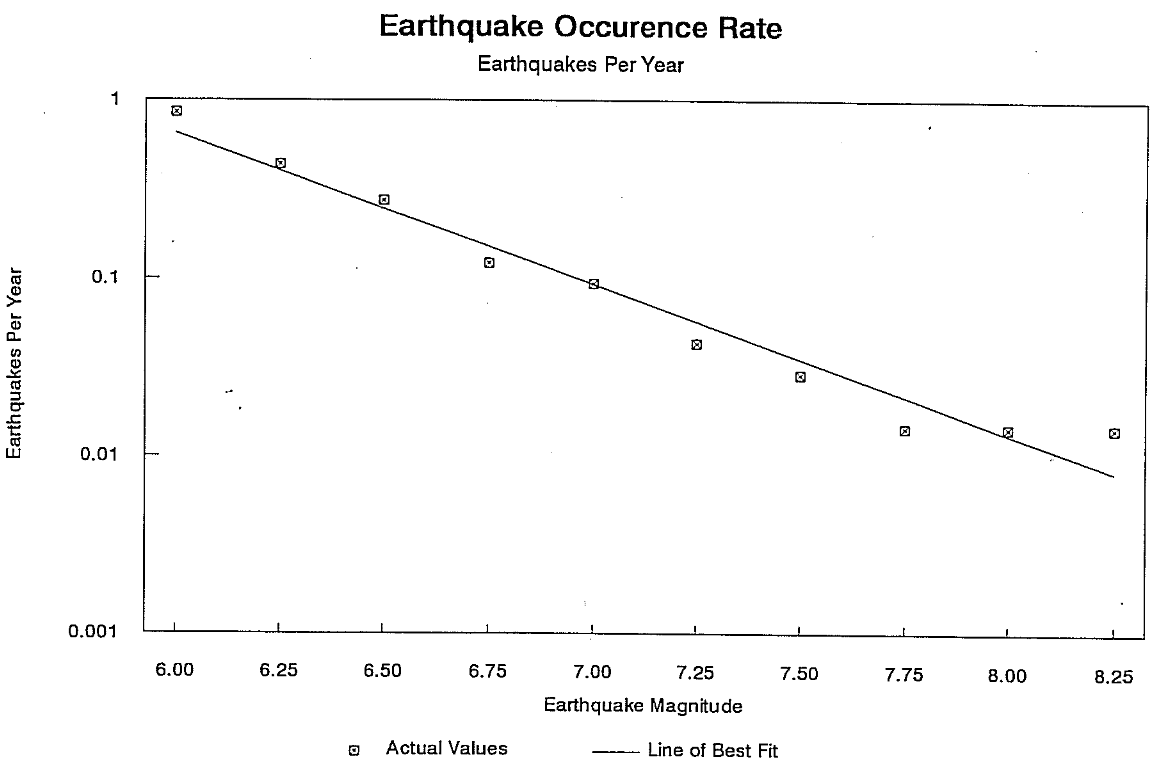
The number of earthquakes with magnitudes greater than, or equal to various values for the 139 year period from 1850 through 1989 are shown in Table 5-3. For example, there were 38 earthquakes during that period with a magnitude $M_L \geq 6.5$. Hence, the annual occurrence rate for earthquakes with $M_L \geq 6.5$ is 0.27 earthquakes per year (38 earthquakes/139 years). That is, on an average, one would expect a $M_L \geq 6.5$ seismic event somewhere in California roughly every 3.7 years (1 event/0.27 earthquakes per year).

The annual occurrence rate data have been plotted semi-logarithmically versus earthquake magnitude in Table 5-3 for all quakes with a Richter magnitude greater than or equal to 6.0. The ordinary least squares line of best fit of the logarithm of the actual occurrence rates yielded an R squared of 0.9633. As explained earlier, this near unity value indicates very strong linearity and little statistical variation. The fitted straight line values shown in Table 5-3 will be used to estimate the likelihood of California's seismic activity for a future 30 year period.

The largest earthquake expected during a 30 year period would have an annual occurrence rate of 0.033 events per year (1 event/30 years). From the straight line fit data shown in Table 5-3, an annual occurrence rate of 0.033 corresponds to a California event with a magnitude of about 7.5. Hence, the largest earthquake expected during a future 30 year period is an event with a magnitude of 7.5 or larger. The table below lists the estimated annual frequency of occurrence and the anticipated number of events during a future 30 year period for various events.

Table 5–3
Annual Occurence Rate For California Earthquakes Based on 1850–1989 U.S. Geological Survey Data

Richter Magnitude	No. of Events with Magnitude Greater Than or Equal To	Actual Occurence Rate (Events per Year)	Straight Line Fit (Events per Year)
6.00	118	0.849	0.655
6.25	61	0.439	0.402
6.50	38	0.273	0.247
6.75	17	0.122	0.152
7.00	13	0.094	0.093
7.25	6	0.043	0.057
7.50	4	0.029	0.035
7.75	2	0.014	0.022
8.00	2	0.014	0.013
8.25	2	0.014	0.008



Event Magnitude (M)	Annual Occurrence Rate (events per year)	Anticipated Number of Events During 30 Year Period
≥ 7.5	0.035	1
≥ 7.0	0.093	3
≥ 6.5	0.247	7
≥ 6.0	0.655	20

We have assumed that the one earthquake expected during a future 30 year period with a magnitude greater than 7.5 would have a local magnitude $M_L \approx 7.75$. The number of events for each of the other magnitudes has been determined by simple subtraction. For example, since we expect 20 events with a magnitude greater than or equal to 6.0, and 7 events with a magnitude greater than or equal to 6.5, we can expect 13 (20 minus 7) events with a local magnitude $M_L \approx 6.25$. The actual number of events expected during a future 30 year period for various magnitudes have been determined in the same manner; these values are shown below.

Local Magnitude (M_L)	Number of Events
7.75	1
7.25	2
6.75	4
6.25	13

5.4 Expected Seismic Incidents

In this section, the number of California hazardous liquid pipeline incidents which are likely to be caused by seismic activity during a 30 year period will be estimated. This will be accomplished by combining the empirical incident rates given in Table 5-2C with the anticipated number of earthquakes during the next 30 years as presented above.

The length of hazardous liquid pipelines exposed to various levels of Modified Mercali Intensities (MMI) can be estimated by multiplying the pipeline density (pipe length per unit land area), by the land area of various MMI zones for different magnitude earthquakes. The following empirical formulas (Toppozada, 1975) relate local magnitude (M_L) (assumed to be equivalent to Richter magnitude M for this study), to the land area shaken at or above various MMI values.

$$M_L = 2.56 + 0.85 \text{ Log } (A_{VI+}) \qquad (1)$$

$$M_L = 3.49 + 0.87 \text{ Log } (A_{VII+}) \qquad (2)$$

$$M_L = 4.30 + 0.87 \text{ Log } (A_{VIII+}) \qquad (3)$$

where: A_{VI+} is the land area in square kilometers having an MMI of VI+ or larger, etc.

For example, equation (2) suggests that about 21,000 square kilometers would experience a modified Mercali intensity of VII or larger for a $M_L = 7.25$ event.

The total areas from equations (1) through (3) must be reduced to account for the fact that earthquakes along the coast or near the state border would generate smaller areas of MMI *within the state* than the equations would indicate. A reduction has been developed based upon a comparison between the measured MMI zone areas for the 1981 through 1990 period with corresponding areas predicted by equations (1) through (3). On average, this comparison suggests that the actual land area *within the state* is roughly one-fifth of the values predicted by the empirical equations. The areas expected to experience various levels of ground shaking are shown in Table 5-2B.

In addition, a relation similar to those in equations (1) through (3) was developed for MMI zone areas for MMI greater than or equal to IX; this was done by noting that shaken areas reduce by a factor of about 10, for a unit increase in MMI. In other words, for a given magnitude event, the area shaken at MMI $\geq$ VII is roughly ten times larger that the area shaken at MMI $\geq$ VIII. The actual equation used is shown below:

$$A_{IX+} \approx \{0.10A_{VIII+} + 0.01A_{VII+} + 0.001A_{VI+}\} \div 3$$

The Table 5-4 values, from equations (1) through (3) modified as described above, have been multiplied by the number of anticipated events of each magnitude to determine the estimated total area which may be expected to experience various levels of ground shaking. This data is shown in Table 5-4A.

The resulting cumulative total land area in California expected to be shaken at specific MMI levels during a 30 year period are as follows:

- MMI = IX — 346 km^2
- MMI = VIII — 3,810 km^2
- MMI = VII — 32,500 km^2
- MMI = VI — 512,000 km^2

Table 5-4
Emperical Areas Exposed to Various Modified Mercali Intensities Versus Local Earthquake Magnitude (Values Shown are One-Fifth Toppozada Values)

Local Richter Magnitude	Affected Area (square kilometers)			
	MMI VI+	MMI VII+	MMI VIII+	MMI IX+
6.00	2,229	153	18	2
6.25	4,387	297	35	3
6.50	8,636	577	68	6
6.75	17,000	1,117	131	12
7.00	33,463	2,165	254	23
7.25	65,868	4,196	492	45
7.50	129,657	8,133	953	87
7.75	255,219	15,761	1,847	170
8.00	502,377	30,545	3,580	332

Table 5-4A
30 Year Estimate of California Earthquakes Areas Affected By Various Sized Events

Estimated Number of Seismic Events	Local Magnitude	Estimated Area (square kilometers)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
1	7.75	255,219	15,761	1,847	170
2	7.25	131,737	8,393	984	89
4	6.75	67,999	4,469	524	47
13	6.25	57,036	3,867	453	40
Total		511,990	32,490	3,808	346

The expected seismic damage to hazardous liquid pipelines is a function of the pipe density in the region. For example, no damage would be expected from earthquakes in Inyo County, (location of the March 26, 1872, Richter magnitude M=7.6 Owen Valley event) or Imperial County (location of the May 18, 1940, Richter magnitude M=7.1 Imperial Valley event) since these counties have no hazardous liquid pipelines (pipe density equals zero). On the other hand, more damage would be expected from an earthquake in Los Angeles County (pipe density = 0.30 kilometers of pipe per square kilometer of land area) or Orange County (pipe density = 0.25 kilometers of pipe per square kilometer of land area).

To bracket the possible results to account for the uncertain nature of the epicenter locations, we will consider three scenarios. Each scenario will include different pipe densities. The number and magnitude of events during the 30 year period will be as presented earlier in Section 5.3.

- Scenario Number 1 - Assume that the epicenter and corresponding MMI zones IX and VIII for the one $M_L \approx 7.75$ event lie in a region with a pipe density of 0.28 kilometers of pipe per square kilometer of land area (similar to Los Angeles and Orange Counties). The other MMI zone areas for the one $M_L \approx 7.75$ event and for all other events (three $M_L \approx 7.25$, seven $M_L \approx 6.75$, and eighteen $M_L \approx 6.25$ events) assume the state wide pipe density average of 0.031 kilometers of pipe per square kilometer of land area.

- Scenario Number 2 - This scenario assumes that all events and all MMI zone areas occur in regions with the state average pipe density of 0.031 kilometers of pipe per square kilometer of land area.

- Scenario Number 3 - Finally, this scenario assumes that the epicenter and corresponding MMI zones IX and VIII for the one $M_L \approx 7.75$ event lie in a region with a pipe density of 0.00 kilometers of pipe per square kilometer of land area (such as Inyo and Imperial Counties). The other MMI zone areas for the one $M_L \approx 7.75$ event and for all other events (three $M_L \approx 7.25$, seven $M_L \approx 6.75$, and eighteen $M_L \approx 6.25$ events) assume the state wide pipe density average of 0.031 kilometers of pipe per square kilometer of land area.

A summary of this data is included in Tables 5-4B, C and D. The estimated number of California hazardous liquid pipeline incidents caused by seismic activity during a future 30 year period are summarized shown below:

MMI Zone	Scenario No. 1 (No. Incidents)	Scenario No. 2 (No. Incidents)	Scenario No. 3 (No. Incidents)
VI	8.57	8.57	8.57
VII	3.22	3.22	3.22
VIII	10.98	2.24	1.16
IX+	5.84	1.18	0.60
Total	28.61	15.21	13.55
Estimated Injuries	2.72	1.45	1.29
Estimated Fatalities	0.17	0.09	0.08

As indicated, we anticipate somewhere between 13 and 29 California hazardous liquid pipeline incidents being caused by seismic activity during a future 30 year period. During the ten year study period, the number of injuries was approximately 9.5% of the number of incidents; the number of fatalities was approximately 0.58% of the number of incidents. Extrapolating these data, we could estimate that seismic activity during a future 30 year period may cause between one and three injuries and may have between a 1 in 6 and 1 in 13 likelihood of causing a fatality.

Table 5-4B
Various Scenarios - Seismic Incident Estimates
California Regulated Hazardous Liquid Pipelines

Scenario 1 - Affected Areas

Estimated Number of Seismic Events	Local Richter Magnitude	Estimated Area (square kilometers)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
1	7.75	0	0	1,847	170
1	7.75	255,219	15,761	0	0
2	7.25	131,737	8,393	984	89
4	6.75	67,999	4,469	524	47
13	6.25	57,036	3,867	453	40

Scenario 1 - Estimated Affected Pipe Lengths

Local Richter Magnitude	Pipe Density (km/km²)	Estimated Pipe Length (kilometers)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
7.75	0.280	0	0	517	48
7.75	0.031	7,912	489	0	0
7.25	0.031	4,084	260	31	3
6.75	0.031	2,108	139	16	1
6.25	0.031	1,768	120	14	1

Scenario 1 - Estimated Number of Incidents

Local Richter Magnitude		Estimated Number of Incidents (incidents per 30 years)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
	Incident Rate	0.00054	0.0032	0.019	0.11
7.75		0.00	0.00	9.83	5.34
7.75		4.27	1.56	0.00	0.00
7.25		2.21	0.83	0.58	0.30
6.75		1.14	0.44	0.31	0.16
6.25		0.95	0.38	0.27	0.14
Total		8.57	3.22	10.98	5.84

Table 5-4C
Various Scenarios - Seismic Incident Estimates
California Regulated Hazardous Liquid Pipelines

Scenario 2 - Affected Areas

Estimated Number of Seismic Events	Local Richter Magnitude	Estimated Area (square kilometers)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
1	7.75	255,219	15,761	1,847	170
3	7.25	131,737	8,393	984	89
7	6.75	67,999	4,469	524	47
18	6.25	57,036	3,867	453	40

Scenario 2 - Estimated Affected Pipe Lengths

Local Richter Magnitude	Pipe Density (km/km^2)	Estimated Pipe Length (kilometers)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
7.75	0.031	7,912	489	57	5
7.25	0.031	4,084	260	31	3
6.75	0.031	2,108	139	16	1
6.25	0.031	1,768	120	14	1

Scenario 2 - Estimated Number of Incidents

Local Richter Magnitude		Estimated Number of Incidents (incidents per 30 years)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
	Incident Rate	0.00054	0.0032	0.019	0.11
7.75		4.27	1.56	1.09	0.58
7.25		2.21	0.83	0.58	0.30
6.75		1.14	0.44	0.31	0.16
6.25		0.95	0.38	0.27	0.14
Total		8.57	3.22	2.24	1.18

Table 5-4D
Various Scenarios - Seismic Incident Estimates
California Regulated Hazardous Liquid Pipelines

Scenario 3 - Affected Areas

Estimated Number of Seismic Events	Local Richter Magnitude	Estimated Area (square kilometers)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
1	7.75	0	0	1,847	170
1	7.75	255,219	15,761	0	0
3	7.25	131,737	8,393	984	89
7	6.75	67,999	4,469	524	47
18	6.25	57,036	3,867	453	40

Scenario 3 - Estimated Affected Pipe Lengths

Local Richter Magnitude	Pipe Density (km/km^2)	Estimated Pipe Length (kilometers)			
		MMI VI+	MMI VII+	MMI VIII+	MMI IX+
7.75	0.280	0	0	0	0
7.75	0.031	7,912	489	0	0
7.25	0.031	4,084	260	31	3
6.75	0.031	2,108	139	16	1
6.25	0.031	1,768	120	14	1

Scenario 3 - Estimated Number of Incidents

Local Richter Magnitude		Estimated Number of Incidents (incidents per 30 years)			
		MMI VI	MMI VII	MMI VIII	MMI IX+
	Incident Rate	0.00054	0.0032	0.019	0.11
7.75		0.00	0.00	0.00	0.00
7.75		4.27	1.56	0.00	0.00
7.25		2.21	0.83	0.58	0.30
6.75		1.14	0.44	0.31	0.16
6.25		0.95	0.38	0.27	0.14
Total		8.57	3.22	1.16	0.60

6.0 Block Valve Effectiveness

Once a pipeline rupture develops, the actual spill volume is comprised of four components:

- discharge through the rupture until it is detected and the shipping pumps are shut-off (this spill volume component will be called *continued pumping*),

- pipeline fluid decompression through the rupture until the block valves are closed,

- continued fluid decompression between adjacent block valves after valve closure, and

- the pipeline drain down.

In this section, we will examine each of these items and how block valves affect the resulting spill volume. The leak data obtained from the pipeline operators in this study will then be examined. Using this data, a cost/benefit analysis for adding additional block valves will be presented. Finally, the results of other studies regarding remotely and automatically operated block valves will be reviewed.

6.1 Continued Pumping

Once a leak develops, it must be detected before corrective action can be taken. The time required for a leak to be detected generally depends on the spill rate, leak location, and the sophistication of the leak detection system, if any, installed.

The total time of continued pumping is comprised of two components. First, the leak must be identified. Second, the pipeline operator must confirm that the alarm or leak report was indeed a leak, initiate pump shut-down, and then wait for the pumps to actually stop. This sequence can vary from only a few minutes for systems with remotely operated pumps, to hours for unmanned, manually operated equipment in remote areas. Some of the factors which affect the second component include:

- type of operating equipment controls (automatically, remotely or manually operated),

- distance of personnel from manually operated shut-down equipment at time of leak discovery,

- work hours of personnel at manually operated facilities (e.g. response times for facilities manned 24 hours per day, 7 days a week are not generally affected by leaks late at night or on weekends),

- communications network, etc.

The time required to identify that a leak exists also varies considerably. For pipelines with modern SCADA systems, which include leak detection software, leaks are often initially detected when alarms sound in the central monitoring facility. Experience has shown that these systems often alarm within only a couple of minutes of a relatively large rupture. There are presently three basic types of leak detection software in general use:

- over/short accounting,

- volumetric balance, with or without line pack corrections, and

- pressure profiling.

Over/short accounting is the traditional method of metering all volumes which enter and leave a pipeline system. The cumulative volumes entering and leaving the system are then compared. This method is useful for detecting small leaks, but requires relatively long time intervals for the cumulative volume difference to become significant enough to be identified. Naturally, the length of time required to identify a leak depends on the actual leak rate. The larger the leak, the shorter the time interval required to detect it and the higher the confidence level that a leak actually exists.

Volumetric balance compares the flow rates of the fluid entering and leaving a pipeline system. Most of these programs include volumetric corrections for pressure and temperature. The performance of these systems vary considerably between different pipelines. They work best on pipelines with relatively constant operating parameters (e.g. flow rate, pressure, temperature, etc.). In some applications (e.g. slack lines) they may have very poor performance. Volumetric balance leak detection systems are generally considered useful in detecting moderate size leaks in a relatively short amount of time.

Pressure profile systems generally have a faster response than the over/short accounting or volumetric balance systems. However, until recently, these systems have only been useful in quickly identifying large spills. When such a spill occurs, a pressure wave travels through the line. The fluctuation is then detected by the leak detection software. The sophisticated software compares the actual fluctuation to anticipated fluctuations which may result from operating condition changes. The system will trigger an alarm if there is a significant discrepancy between the anticipated and actual situation.

For pipelines without leak detection systems, and frequently for relatively slow, small leaks from pipelines with leak detection systems, leaks are often discovered after fluid pools on the earth's surface. Depending on the location, it may be discovered by the public, by the pipeline operator during his line patrol, etc. The time required may range from minutes, up to several days for these leaks to be identified.

For a given leak size, the spill volume due to continued pumping (V_p) can be calculated using the following equation:

$$V_p = Q * (T_1 + T_2)$$

where: V_p = spill volume caused by continued pumping (barrels)
Q = leak size flow rate (barrels per minute)
T_1 = time required to detect leak (minutes)
T_2 = time required to shut-off pumps (minutes)

6.2 Fluid Decompression

Although we normally consider fluids incompressible, petroleum fluid volumes at atmospheric pressure for pipelines operated at high pressure are much greater than one might expect. Once a leak develops, the fluid volume increases as pressure is released through the rupture. This occurs in two steps. First, between pump shut-down and block valve closure, a portion of the entire line pack is spilled. For short block valve closure time intervals, this volume can be estimated as follows:

$$V_{d1} = T_3 * Q_L$$

where: V_{d1} = partial decompression spill volume (barrels)
Q_L = leak flow rate (barrels per minute)
T_3 = time interval between pump shut-down and valve closure (minutes)

For extremely long block valve closure intervals, the decompression spill volume approaches the total *line pack*, or the difference in pipeline volume between ambient and actual operating conditions. For intermediate valve closure times, the decompression spill volume is rather difficult to calculate. However, a reasonable approximation could be made by interpolation.

The second component occurs from the remaining decompression between the closed block valves on either side of the rupture. This value can be estimated as follows:

$$V_{d2} = L_1/L_2 * (P - V_{d1})$$

where: V_{d2} = partial decompression spill volume (barrels)
L_1 = distance between adjacent block valves (miles)
L_2 = total pipeline length (miles)
P = line pack (barrels)

The total fluid decompression spill volume can then be determined by adding the sum of the spill volumes before and after valve closure ($V_{d1} + V_{d2}$).

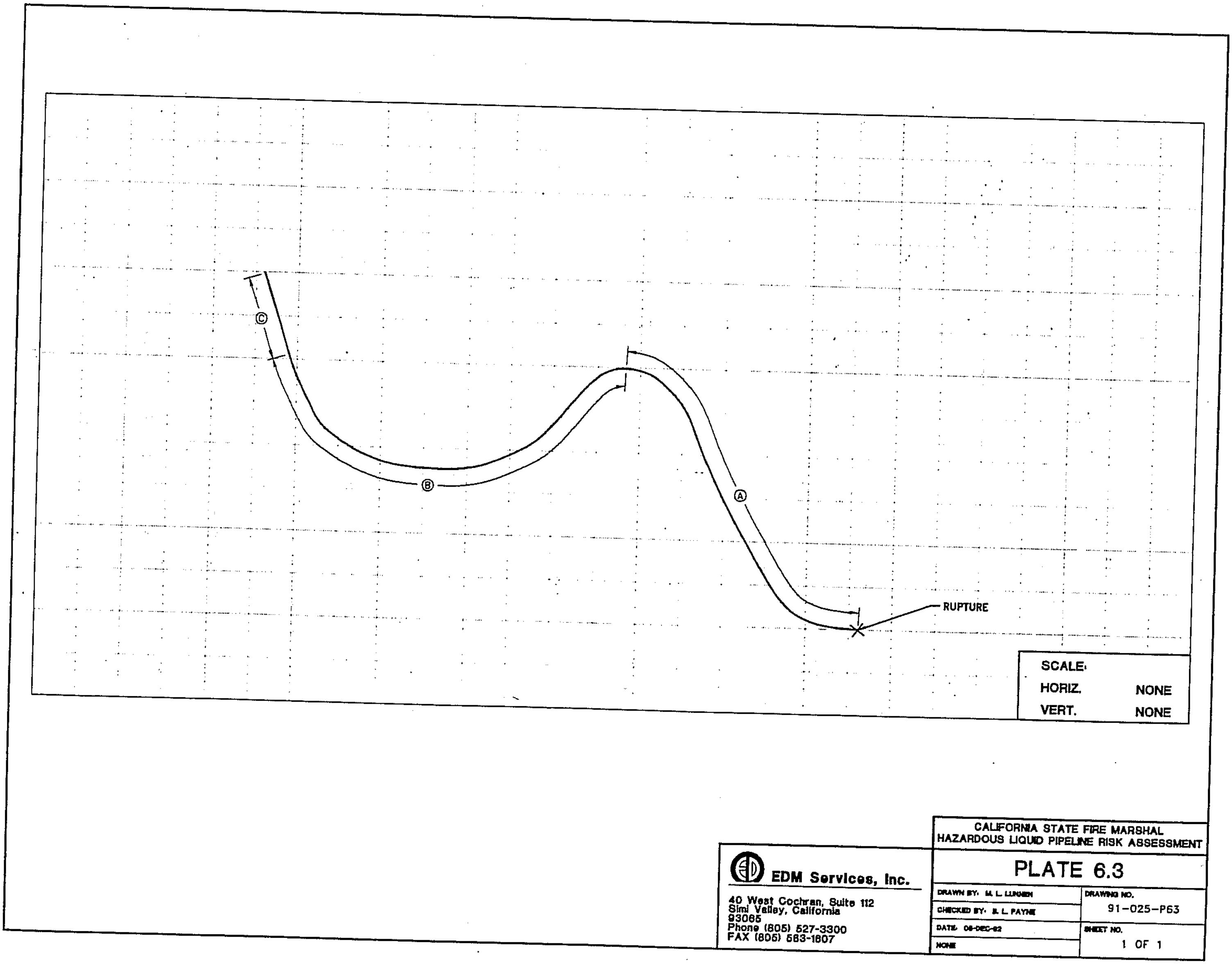
6.3 Drain Down

The final spill volume component, drain down, is the most difficult to predict. It is directly related to the leak location and the pipeline profile. Often this volume varies considerably for various locations along a given line. For example, a rupture at the highest point of a line would not result in any drain down volume. On the other hand, a leak in a low section could result in a significant drain down; in some cases it could include the total volume of line between adjacent block valves on either side of the rupture. As we will see in Section 6.5, in most instances, the actual drain down spill volume is only a small fraction of the total distance between adjacent block valves.

The rate at which fluid will drain from a leak is difficult to predict. It depends, among other things, on the size of the leak, the pipeline profile, the fluid viscosity, etc. Often, the fact that the pipeline section is a *closed* system is overlooked. In order for fluid to drain from the line, air must enter to displace the fluid. This is somewhat similar to turning a full soda pop can up-side-down; the soda would spill relatively slowly as air *bubbles* into the can to displace it. If however, a hole is made in the top of the can to allow air to enter, soda will flow readily, since air will be available to displace it.

In hilly or mountainous terrain, determining the length of line which will drain from a rupture is not straightforward. Consider the example shown on Plate 6.3. The length "A", from the rupture to the crest of the first hill, will drain as air *bubbles* into the line as previously discussed. However, air will not move past the hill crest, since the pressure in the line beyond the crest is greater than atmospheric. The length "B" will not drain from the line; it will remain pocketed in the low section. The amount of segment "C" which will drain is difficult to determine. Since air can't migrate into the section to displace the fluid, the fluid will pull a vacuum on the upper section of pipe, equal to the weight of the vertical column of fluid. Depending on the fluid, various volumes of light hydrocarbons will *gas off*. As this occurs, some percentage of the length "C" will drain from the rupture.

Plate 6.3


C
B
A
RUPTURE
SCALE:
HORIZ. NONE
VERT. NONE
EDM Services, Inc.
40 West Cochran, Suite 112
Simi Valley, California
93065
Phone (805) 527-3300
FAX (805) 583-1607
CALIFORNIA STATE FIRE MARSHAL
HAZARDOUS LIQUID PIPELINE RISK ASSESSMENT
PLATE 6.3
DRAWN BY:
CHECKED BY:
DATE:
NONE
DRAWING NO.
91-025-P63
SHEET NO.
1 OF 1

This situation is significantly different than for gas pipelines, where the entire line segment contents are released into the atmosphere. As shown in the example, the terrain frequently creates natural check valves on liquid lines which prevent large percentages of the total pipeline volume from being spilled. This principle makes direct comparison between block valve effectiveness on liquid and gas lines impossible.

6.4 Spill Components Affected By Block Valves

The effectiveness of block valves on hazardous liquid pipeline spill volumes is directly related to:

- the leak's physical location in relationship to the valve,
- the pipeline profile, and
- the time required to close the valve once a leak has been identified.

For example, a block valve would be very effective in minimizing the drain down portion of a spill caused by a leak immediately downslope from it, assuming it could be readily closed. On the other hand, in many cases it would have no affect on the drain down portion of a spill immediately upslope, even if it could be immediately closed.

In addition to potentially reducing drain down spill volumes, block valves which can be closed immediately after pump shut-down may also slightly reduce the fluid decompression spill volumes. (See also Section 6.2.).

Block valves do not reduce spill volumes caused by continued pumping. This spill volume can only be reduced by rapid leak identification and pump shut-down. Modern SCADA systems, utilizing leak detection software, are effective in reducing this spill volume component.

In short, for hazardous liquid pipelines:

- Block valves are only effective in significantly reducing the drain down component of a spill. In many instances, the terrain reduces the actual drain down volume to only a fraction of the distance between adjacent block valves.

- Block valves are not effective in significantly reducing the total spill volume unless the leak can be quickly identified. Installing additional block valves on a line without a leak detection system (either continuous visual monitoring or modern SCADA system with leak detection) is somewhat like putting the cart before the horse.

- Finally, in many cases, block valves effectiveness decreases as the length of time required to close them increases.

6.5 Block Valve Effectiveness Data

Some earlier studies have assumed that block valve effectiveness is directly related to the length of line between adjacent valves. Following this logic, it has been assumed that by reducing the distance between block valves by say a factor of two, the resulting spill volume and subsequent damage would be halved. While this may be partially true for gas lines, it is certainly not the case for most hazardous liquid pipelines, as we shall see. Even if the spill volume could be reduced in direct proportion to block valve spacing, the resulting damage would not be proportionally reduced; in most cases, the first barrels spilled result in much more costly damage, injury and loss of life than subsequent barrels spilled.

During data collection, the EDM Services' technicians attempted to gather information which would facilitate a block valve effectiveness analysis. To this end, the spill volume and the distance to the nearest block valve on each side of each leak were collected. In addition, data was collected from each pipeline operator regarding the total pipeline lengths and number of block valves installed on each of their regulated hazardous liquid pipelines. This data is summarized below:

Number of Pipe Sections With Block Valve Data	552 Pipelines
Average Block Valve Spacing	3.12 Miles
Median Block Valve Spacing	1.39 Miles
Total Number of Intermediate Block Valves Installed	1,909 Valves
Total Length of Pipelines With Block Valve Data	7,679 Miles

This valve spacing data has also been depicted graphically in Table 6-5A. The large variation between the average and median block valve spacings indicate that the few pipelines with high average block valve spacings affected the average value considerably. This fact is also shown by the shape of the curve on Table 6-5A. The following values are worth noting:

- 25% of the pipeline systems had an average block valve spacing of 0.52 miles or less.
- 50% of the pipeline systems had an average block valve spacing of 1.39 miles or less.
- 75% of the pipeline systems had an average block valve spacing of 3.00 miles or less.
- 90% of the pipeline systems had an average block valve spacing of 6.36 miles or less.
- Only 22 pipelines (4% of the total) had average block valve spacings of 10.00 miles or more. Only 15 of these pipelines were over 20 miles long.
- The longest average block valve spacing on an individual pipeline was 56 miles.

Similar data was also collected for each of the leaks included in the study for which such information was available. These data included the distance to the nearest block valve on either side of the rupture, the spill size, and various other specific data. They are summarized below:

Number of Leaks With Adjacent Block Valve Distance Data	454 Leaks
Average Total Distance Between Adjacent Block Valves On Each Side of Leak	6.13 Miles
Median Total Distance Between Adjacent Block Valves On Each Side of Leak	3.4 Miles
Average Spill Size	419 Barrels
Median Spill Size	5 Barrels

Table 6-5B presents the distribution of the total distance between the adjacent block valves on either side of each leak. These lengths were then added to determine the total length of line which could drain down through the rupture. (This length will also be referred to as the *maximum potential drain down length*.) As noted above, we were able to compile this data for 454 (88%) of the leaks included in this study. Various values along the distribution curve are presented below:

- 25% of the leaks had a maximum potential drain down length of 1.4 miles or less.
- 50% of the leaks had a maximum potential drain down length of 3.4 miles or less.
- 75% of the leaks had a maximum potential drain down length of 8.1 miles or less.
- 90% of the leaks had a maximum potential drain down length of 16.6 miles or less.
- 95% of the leaks had a maximum potential drain down length of 18 miles or less.
- The longest maximum potential drain down length for an individual leak was 71 miles. (It's interesting to note that the leak which occurred on this segment resulted in only a one barrel spill.)

Table 6-5C presents the distribution of spill sizes for the 454 leaks with adjacent block valve distance information. As indicated, the vast majority of the leaks had very small spill volumes. However, a few relatively large spills resulted in an average spill size much higher than the median, 419 versus 5 barrels. The shape of this curve is virtually identical to the spill size distribution curve presented in Table 4-22 for all leaks included in the study.

As discussed in the prior subsections, block valves are only effective in controlling a portion of the total spill volume. One method of evaluating block valve effectiveness in controlling spill volumes is to examine the percentage of the maximum potential drain down which was actually spilled. This was done for each of the 454 incidents with adjacent block valve distance data as follows:

Table 6–5A
Average Valve Spacing Distribution
All Pipelines Included In Study

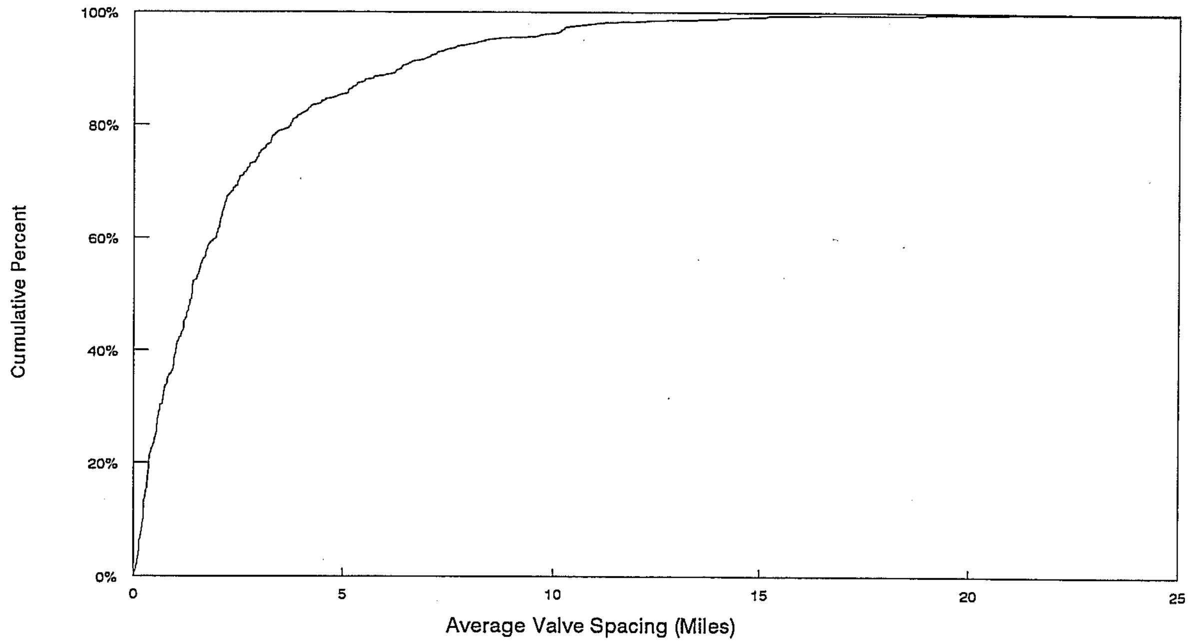
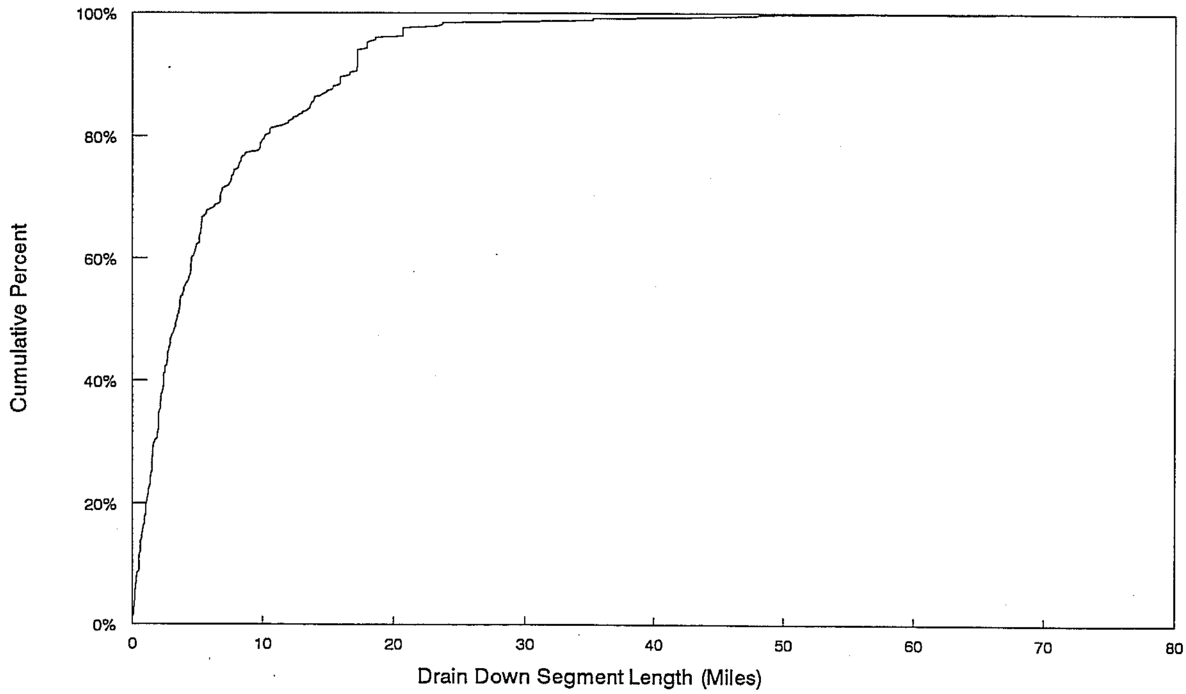


Table 6–5B
Potential Drain Down Length Distribution
For Leaks With Adjacent Valve Spacing Distances



- The length of pipe with an internal volume equivalent to the spill volume was calculated for each leak using the following equation:

  $L_{Leak} = (0.15315 * V_{Spill}) \div \{3.1416 * (O.D./2 - w.t.)^2\}$

  where: L_{Leak} = Equivalent Pipe Length (miles)
  V_{Spill} = Spill Volume (barrels)
  O.D. = Outside Pipe Diameter (inches)
  w.t. = Pipe Wall Thickness (inches)

- The maximum potential drain down length was determined by adding the distance to the nearest adjacent block valves.

  $L_{Drain} = L_{V1} + L_{V2}$

  where: L_{Drain} = Maximum Potential Drain Down Length (miles)
  L_{V1} = Distance to Nearest Upstream Block Valve (miles)
  L_{V2} = Distance to Nearest Downstream Block Valve (miles)

- The percentage of the maximum potential drain down which was actually spilled was then determined for each leak by simple division as follows:

  $\%_{Drain} = L_{Leak} \div L_{Drain} * 100\%$

  where: $\%_{Drain}$ = Portion of the Maximum Potential Drain Down Which Actually Spilled (Percent)

The results of this analysis are presented in Table 6-5D. As indicated, 75% of all leaks resulted in spill volumes which comprised only 4.5% or less of the maximum potential spill volume between the nearest adjacent block valves. The actual values corresponding to some of the other points along this curve are given below:

- 25% of the spill volumes represented less than 0.14% of the maximum potential drain down volume between adjacent block valves.

- 50% of the spill volumes represented less than 0.75% of the maximum potential drain down volume between adjacent block valves.

- 75% of the spill volumes represented less than 4.6% of the maximum potential drain down volume between adjacent block valves.

Table 6–5C
Spill Size Distribution
For Leaks With Adjacent Valve Spacing Distances

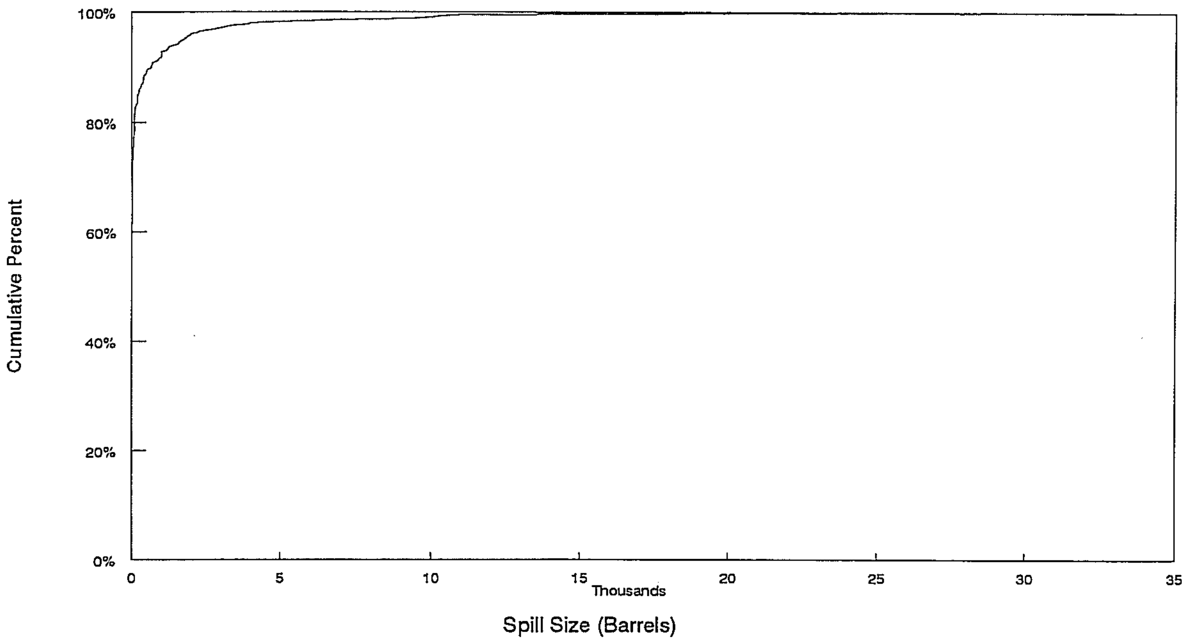
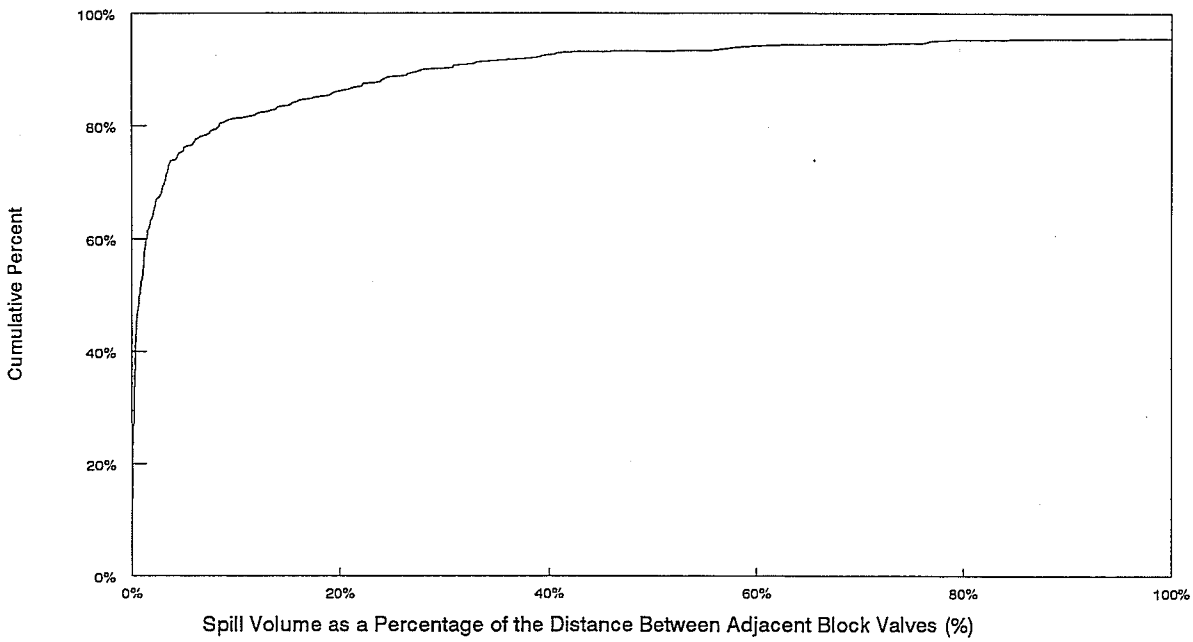


Table 6–5D
Distribution of Spill Volumes
As A Percentage of The Distance Between Adjacent Block Valves
(For Leaks With Adjacent Valve Spacing Distances)



- 80% of the spill volumes represented less than 8.5% of the maximum potential drain down volume between adjacent block valves.

- 90% of the spill volumes represented less than 28% of the maximum potential drain down volume between adjacent block valves.

- Only 6.4% of the total number of incidents resulted in spill volumes which were greater than 50% of the maximum potential drain down volume between adjacent block valves.

- Only 4.6% of the total number of incidents resulted in spill volumes which were greater than the maximum potential drain down volume between adjacent block valves.

The actual effect of each spill volume component (e.g. continued pumping, drain down, etc.) was impossible to evaluate with the data available. As a result, the values presented above represent the effects of *all* spill volume components.

For example, for 50% of the leaks, the actual spill volume was less than 0.75% of the total volume between block valves. Considering spill volume components which are not affected by block valves (e.g. continued pumping), the actual spill volume which could have been affected by closer block valve spacing would have been somewhat less than 0.75%. These results indicate that other factors (e.g. natural terrain) considerably reduced the spill volumes associated with leaks on California's regulated hazardous liquid pipelines. From this data, one could conclude that the number of block valves would have to be increased by at least 100 times, in order for block valve effectiveness to begin to approach a direct relationship between block valve spacing and resulting spill volumes for the majority of pipeline leaks.

Looking at this another way, *neglecting all other spill volume components*, reduced block valve spacing could have *directly* affected spill volumes on a maximum of only 4.6% of the incidents.

The spill sizes versus the maximum potential drain down lengths (L_{Drain}) are plotted in Table 6-5E. As shown, the vast majority of this data indicates relatively small spill volumes, regardless of the distance between adjacent block valves. However, a few very large volume spills are scattered among the data.

A line was fitted to this data using the least squares method. Although the line resulted in a slightly increasing trend, 46 barrels per additional mile between adjacent block valves, the resulting *R squared* was a very low 0.027.

The data presented in Table 6-5E does not consider pipe diameter variations. Since the spill volume from a given length of potential drain down is related to the square of the pipe diameter for a given size spill, the results contain some inherent error. As a result, a separate analysis was performed after normalizing the data to correspond with 12.750" outside diameter, 0.250" wall thickness pipe. (These values are very close to the mean pipe diameter and wall thickness values for all pipe included in the study.) The data was normalized by multiplying the actual spill volumes by the ratio of the actual leak pipe cross sectional area divided by the cross sectional area of 12.750" outside diameter, 0.250" wall thickness pipe.

The resulting *normalized* spill volumes versus the maximum potential drain down lengths are shown on Table 6-5F. As before, the vast majority of these data showed very small spill volumes, regardless of the distance between adjacent block valves. However, a few very large volume spills were scattered among the data.

A line was fitted to this data using the least squares method. The line resulted in a slightly increasing trend, 31 barrels per mile; however, once again the resulting *R squared* was a very low 0.017.

In other words, after normalizing the data, although not statistically relevant, reduced block valve spacing would result in a 31 barrel spill volume reduction per mile of block valve spacing reduction. Taking this one step further, if the number of block valves were doubled on California's regulated pipeline systems by adding 1,909 valves, the average block valve spacing would be reduced from 3.12 miles to 1.76 miles. This would result in only a 13% reduction in overall spill volumes, from 325 to 283 barrels. The overall reduction in damage would likely be much less than 13%.

6.6 Cost Benefit Analysis

Although there is little statistical correlation between block valve spacing and the resulting spill size, a simple cost benefit analysis will be presented in this section for completeness. The reader is cautioned against using this information for anything more than a benchmark; the very low statistical relationship between block valve spacing and spill size provides little merit to the results. Further, it is possible that additional valves may increase the likelihood of leaks occurring; the data presented in this section does not include any correction for leaks which may result from additional valves.

The *normalized* values presented by the least squares line of best fit shown in Table 6-5F will be used to estimate the benefits associated with additional block valves. As stated earlier, this line of best fit has a slope of 31 barrels per mile of block valve spacing reduction. For our average block valve spacing of 3.12 miles, the line of best fit indicates a 325 barrel spill size.

Table 6–5E
Spill Size Versus Drain Down Length
Raw Data – Unadjusted For Pipe Diameter Variations

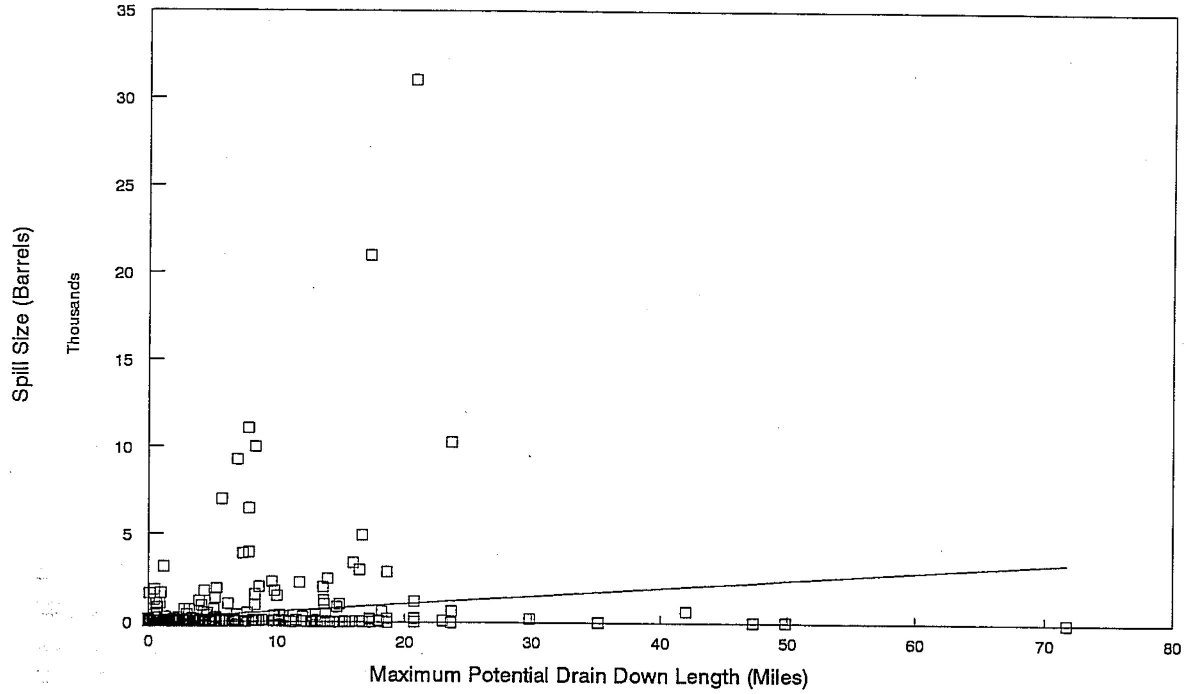
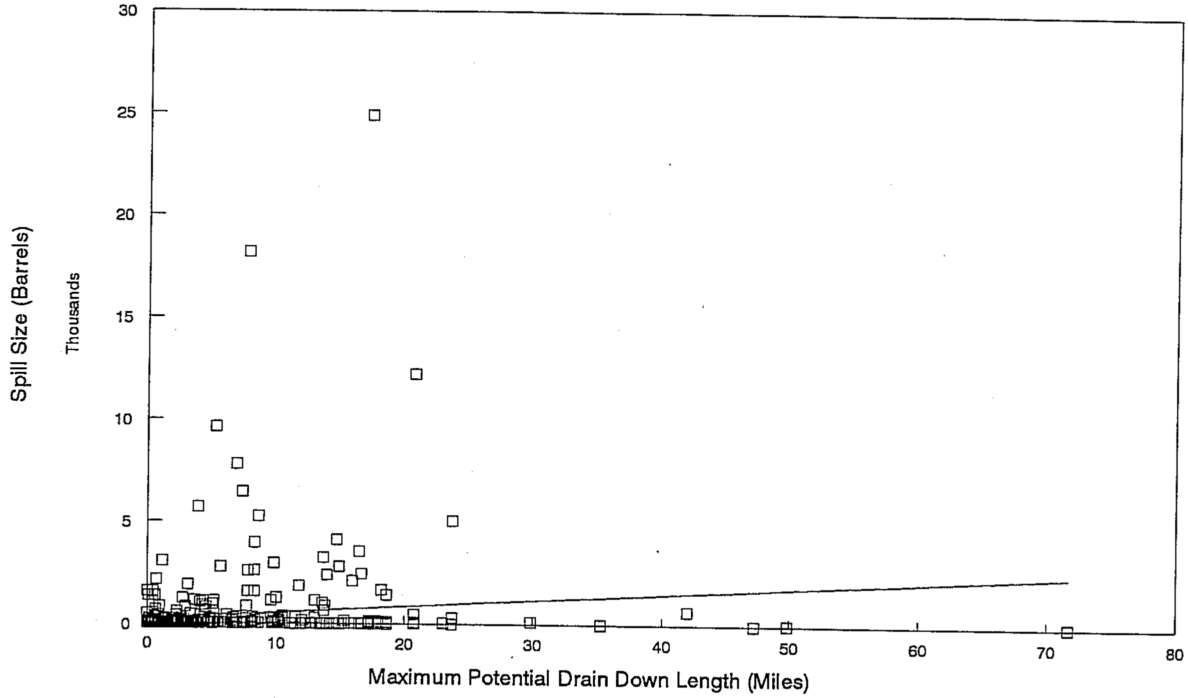
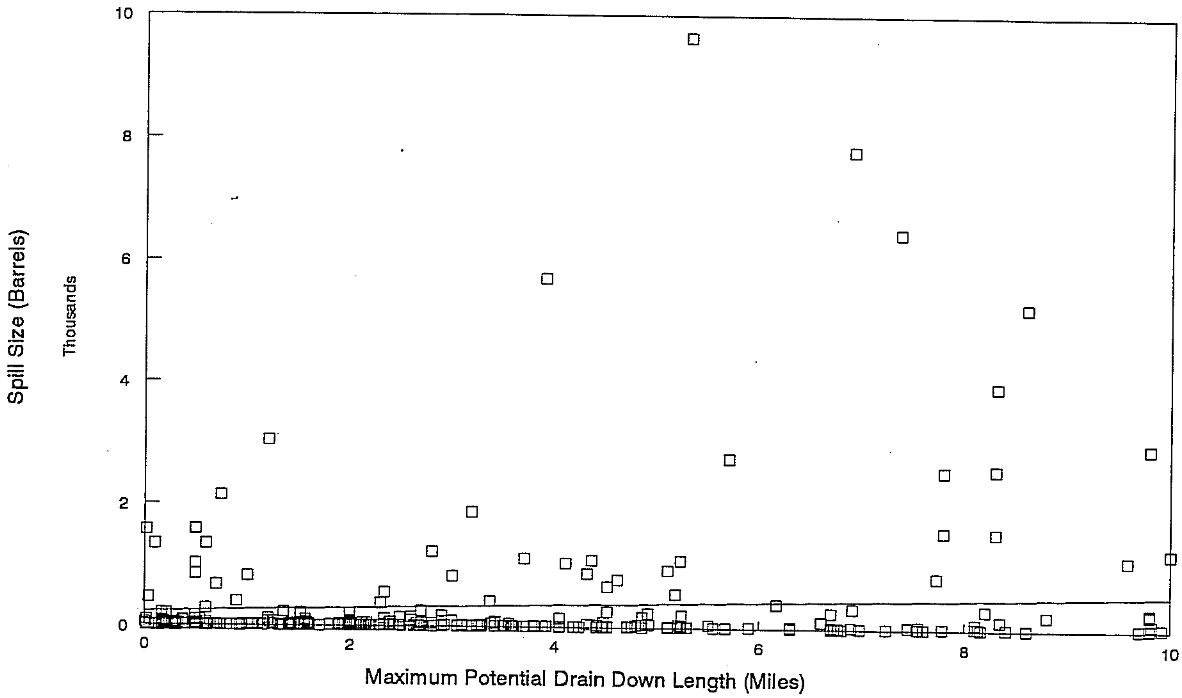


Table 6-5F

Spill Size Versus Drain Down Length
Adjusted Data – Normalized For 12.75" O.D., 0.25" W.T.



Spill Size Versus Drain Down Length
Adjusted Data – Limited Range



The approximate unit costs associated with adding additional block valves, as used in the analyses, are itemized below:

· Cost per additional block valve installation	\$25,000/Valve
· Additional Block Valve Maintenance	\$500.00/Valve/Year
· Useful Line	20 Years

For the purposes of these analyses, we assumed that the cost of maintenance would increase at the same rate as inflation.

The approximate benefits used in the analyses are shown below:

· Average Damage	\$141,000/Leak
· Rate of Damage Increase	\$23,000 Per Year
· Inflation	7%/Year
· Average Spill Size	408 Barrels (bbl)
· Average Cost Per Barrel Spilled	\$346/Barrel
· Spill Volume Reduction	31 bbl/Mile Valve Spacing Reduction
· Probability of Leak	7.3 Incidents/1,000 Mile Years

In evaluating the potential benefits associated with additional block valves, there was one significant unknown, the relative value of minimizing additional fluid being spilled. Specifically, block valves do not prevent leaks; they are only effective in minimizing a portion of the spill volumes associated with them. We believe that the costs associated with the last barrels spilled are far less than the first few barrels spilled.

For example, consider our average 408 barrel spill. If additional block valves were added to reduce the average spill volume 25%, to say 306 barrels, we would not expect the average damage to be reduced by a corresponding 25%. We would expect the average damage value to be reduced little, if any, by this action. However, we do not have data available to quantify this position.

As a result, in the two scenarios which follow, the cost benefit analyses were performed assuming various values for this unknown. Cost benefit ratios were determined assuming 10%, 25% and 50% values for this unknown. We believe that the actual value was likely between 10% and 25%. In other words, if the average spill volume could be reduced say 25%, the value of the reduced spill volume would be between 10% and 25% of the value calculated using average damage per barrel spilled figures; this would result in an overall damage reduction of between 2.5% and 6% (10% of 25% and 25% of 25% respectively).

For the first scenario, we examined the relative benefits associated with adding various numbers of valves to California's regulated hazardous liquid pipelines. The analyses considered adding between 250 to 1,909 valves to the existing pipeline systems. Adding these valves would result in an average valve spacing reduction from 3.12 miles, to between 2.83 miles and 1.76 miles respectively (depending on the actual number of additional valves). The results are shown graphically in Table 6-6A. The raw data, using a 10% effectiveness factor, is shown below.

	250 Valves	500 Valves	1,000 Valves	1,909 Valves
Estimated Cost (Present Value)	$8,750,000	$17,500,000	$35,000,000	$66,815,000
Estimated Benefit (Present Value)	$402,000	$737,000	$1,261,000	$1,907,000
Cost Benefit Ratio	21.8 : 1	23.7 : 1	27.7 : 1	35.0 : 1

As stated earlier, by doubling the number of block valves on California's regulated pipeline systems from 1,909 to 3,818, the line of best fit indicates that the average spill volume would only be reduced 13%, from 326 to 283 barrels. The resulting damage would be reduced by between 1.3% and 3%, in our judgement.

The second scenario considered six 12" pipeline segments ranging from one to ten miles. Separate analyses were made for each segment, assuming the addition of one intermediate block valve at the middle of each segment. The results are depicted graphically in Table 6-6B. The cost benefit ratios for the various effectiveness factors and segment lengths considered are shown below.

Pipe Segment Length	10% Factor	25% Factor	50% Factor
1 Mile	384 : 1	153 : 1	76.8 : 1
2 Miles	96.0 : 1	38.4 : 1	19.2 : 1
3 Miles	42.7 : 1	17.1 : 1	8.54 : 1
4 Miles	24.0 : 1	9.60 : 1	4.80 : 1
5 Miles	15.4 : 1	6.15 : 1	3.07 : 1
10 Miles	3.84 : 1	1.54 : 1	0.77 : 1

Table 6–6A
Cost Benefit Ratios
Additional Block Valves On All California Regulated Pipelines

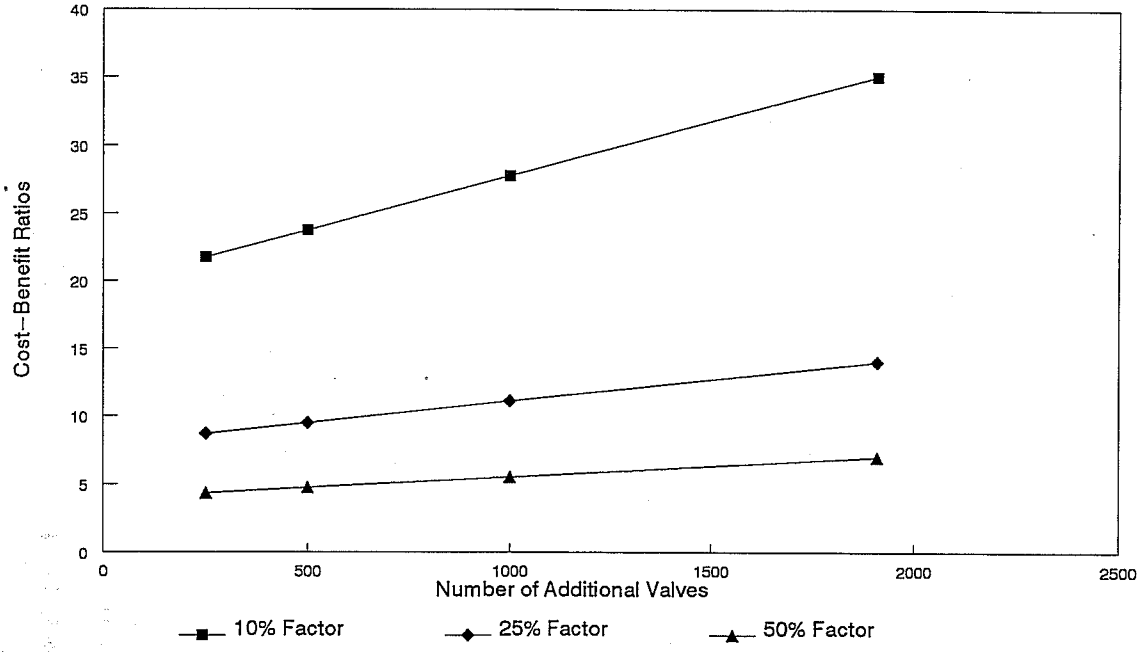
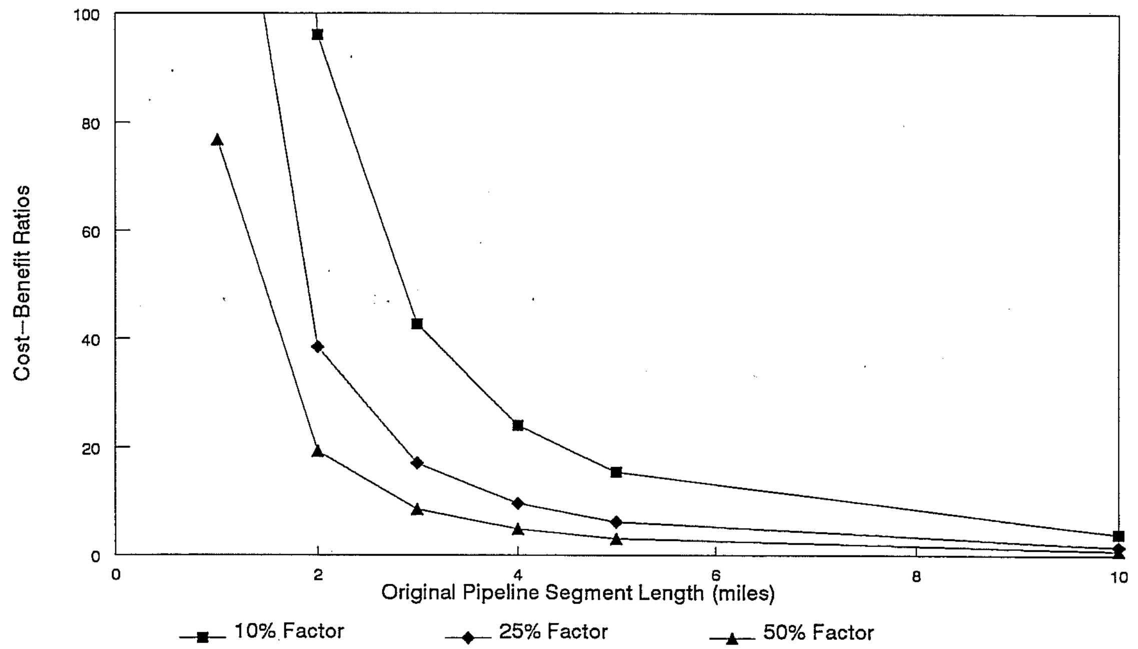


Table 6–6B
Cost Benefit Ratios
Additional Block Valves On Individual Line Segments



This data indicates that there may be some justification for additional block valves on very long segments of pipeline. However, since natural terrain and other factors affect each situation differently, each case would require individual investigation.

For completeness, it should be noted that some have argued that cost benefit analyses are not appropriate for analyzing the effects of various aspects of pipeline regulations. While not necessarily the authors' opinion, this view was summarized in the National Transportation Safety Board's Special Study of Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown - Report Number NTSB-PSS-81-1, December 30, 1970, which stated,

> "The degree of security to be provided by pipeline regulations has sometimes been assessed by applying cost-benefit criteria. How much larger is the amount of loss to be prevented than the cost necessary to prevent this loss? This criteria is applicable to a situation when the benefits in reduced risk and the costs are shared within the same group. However, the risks and losses from pipeline accident exposure and the costs of hazard reduction are not within the same group.
>
> Those at risk from pipeline accidents are sometimes employees of the system; more often they are members of the general population who happen to live near a pipeline, or to be near it by chance. These people may not benefit from a given type of pipeline transportation, even indirectly. At most, they benefit from the service only to the same degree as others in the population. These people do, however, carry the risk for the benefit of the rest of society. The benefitting groups in society are the natural gas or liquid fuel users and the profit making institutions which operate the lines. One way to equalize this risk would be to reduce it to zero, so that those near the pipeline have the same risk as those who benefit from the pipeline service. Alternately, since it is not possible to reduce a risk to zero, funds could be employed to reduce the risk to a point well below what would be justifiable by requiring the benefits to match or exceed the costs. Those who are bearing the risk deserve to be protected by expenditures far beyond the dictates of cost benefit."

6.7 Cost Benefit Analysis - HVL Lines

In January 1978, a Notice of Proposed Rulemaking was issued regarding pipelines carrying highly volatile liquids (U.S. Department of Transportation, Docket Number PS-53). This rule proposed that valves be located no more than 7 1/2 miles apart when relocating, replacing, or otherwise changing existing steel highly volatile liquid (e.g. propane, ethane, butanes, and anhydrous ammonia) pipeline systems in inhabited areas. The proposal resulted from the Department's findings that highly volatile liquid pipeline accidents generally caused more damage to life and property than non-highly volatile liquid pipeline accidents. The proposed rule stated in part, "Each sectionalizing valve on a pipeline in an inhabited area that transports highly volatile liquid must be either equipped for operation at an attended location or designed to operate automatically unless it is located 3.7 miles or less from a sectionalizing valve that is so equipped or designed."

The American Petroleum Institute published A Cost benefit Analysis of Proposed Safety Regulation of Valve Spacing and Operation in May 1979. It presented the results of questionnaires from 61 pipeline systems, 218 highly volatile liquid pipeline accidents, and public information. The cost and benefit impacts were presented for existing lines only; they did not include an analysis of newly constructed lines. Briefly, the study found:

- The cost to benefit ratio was at least 40:1. As a result, the study found that, "...when the relation of total benefits to total costs for society as a whole is considered as a criteria in judging the desirability of regulation, the proposed regulation is ineffective and wasteful." In addition to property damage, values of $1,000,000 for life and $250,000 per injury were used in the analyses ($U.S. 1979).

- The average cost to add new valves was $48,850 per valve. (Converting to $U.S. 1983, to be consistent with other data presented in this report, yields an average of $67,286.)

- The average cost to convert existing valves was $30,700. (Converting to $U.S. 1983, to be consistent with other data presented in this report, yields an average of $42,286.)

- The study stated that additional remotely actuated or automatic valves would cause additional accidents since the valves themselves could leak or malfunction. Further, the valves could be closed unintentionally, as a result of a malfunctioning automatic or remote closing apparatus, causing other operational problems.

- 86 accidents occurred on sections in inhabited areas which were bracketed by block valves less than 7.5 miles apart. These incidents accounted for 84% of the deaths, 48% of the injuries, and 39% of the property damage among all incidents. The study suggests that this indicates that closer valve spacing contributes little or nothing to hazard reduction.

6.8 Emergency Flow Restricting Devices

In March 1991, the U. S. Department of Transportation published a study entitled, Emergency Flow Restricting Devices Study, regarding emergency flow restricting devices. This study was intended to fulfill the requirements of Section 305 of the Pipeline Safety Reauthorization Act of 1988. For this study, only remotely controlled block valves (RCV) and check valves were considered emergency flow restricting devices. Since pipeline safety could be adversely affected by the installation of automatic control valves, they were not included in the study. The study findings are outlined below:

- The study considered five scenarios. The analyses considered four criteria: safety, cost, feasibility and effectiveness. However, complete cost data was only available for one of the scenarios, hazardous liquid pipelines in urban areas.

- Although data was not available to perform a cost benefit analysis, the study concluded that requiring the retrofitting of all existing manually operated valves to RCV's on hazardous liquid pipelines in rural locations was probably not justified due to the high cost involved. (The study assumed a cost of $40,000 per valve to convert from manual to remote actuation.)

- For hazardous liquid pipelines in urban areas, the study *assumed* that installing RCV's, in lieu of manually operated valves, would result in a 75% reduction in all safety and environmental accident effects. (This assumption was not substantiated.) Using this assumption, the analysis concluded that converting existing manually operated block valves to RCV's would have a 1:1.59 cost benefit ratio. Adding additional RCV's resulted in a 1:1.24 cost benefit ratio. However, the study noted that RCV's would only be effective on systems with effective SCADA systems with leak detection sub-systems.

- Underwater RCV's as emergency flow restricting devices on offshore pipelines were not recommended because of their unreliable operation.

- The study concluded that past pipeline operating experience obviated the need for a demonstration project.

In July 1987, the American Petroleum Institute published a report which included a section on this topic. Regarding the costs and benefits associated with converting existing block valves to automatic or remote operation, the study, entitled The Safety of Interstate Liquid Pipelines: An Evaluation of Present Levels and Proposals for Change, found:

- The capital cost to equip the 7,018 manually operated valves which are not used for facility isolation for remote actuation would be $299 million, or an average of $42,000 per valve. Operating costs for these valves would be an additional $17 million per year, or $2,400 per valve per year.

- The capital cost to equip the locally operated valves used for station isolation for remote actuation would be $406 million, plus an additional $22 million annual year operating cost.

- By reviewing detailed information available for 336 accidents, the study found that only 55% of the accidents could have potentially benefitted from remote or automatic valve operation. These 187 accidents resulted in 31% of the fatalities, 26% of the injuries, and 37% of the property damage. Using this data, one could conclude that the actual effect of converting manually operated valves to remote operation would result in benefits which would be some fraction of these percentages of the total fatality, injury and property damage figures.

  Extrapolating this data to cover all pipeline incidents, the study found that the maximum potential benefit would be $7 million per year, at an annual cost of $109 million. The resulting cost benefit ratio was 15:1.

A third study, Rapid Shutdown of Failed Pipeline Systems and Limiting of Pressure to Prevent Pipeline Failure Due To Overpressure, was prepared by Mechanics Research, Inc. for the Department of Transportation in October 1974. This study also addressed the effectiveness of remotely controlled block valves on hazardous liquid pipelines. This study found,

- Adding leak detection and remotely operated valves to existing pipelines in populated areas would result in a 18:1 cost benefit ratio using a 20 year useful life.

- Adding leak detection and remotely operated valves to all new pipelines constructed in populated areas would result in a 56:1 cost benefit ratio using a 20 year useful life.

7.0 Local Fire Agency Notification

The contract work scope for this study required an analysis of the feasibility of pipeline operators notifying local affected fire agencies of their pipeline contents and any changes in the hazardous liquids being transported. Existing pipelines would fall into two categories if these requirements should become law:

- Pipelines which carry a single type of fluid - These lines would only require a single notification of the local fire agencies. Most operators already include this notification in their public awareness programs. Many operators forward a copy of their Thomas Guide map book overlays to each local fire agency. These overlays show the location of the hazardous liquid pipelines and often show their contents as well.

- Pipelines which periodically have changes of their contents - These lines would require the operators to notify local fire agencies each time the contents changed. For a pipeline traversing several different local fire agency jurisdictions, each fluid change would require a number of notifications.

Intrastate lines which carry a single type of fluid are already required to meet these requirements; current state law states that, "Every pipeline operator shall provide to the fire department having fire suppression responsibilities a map or suitable diagram showing the location of the pipeline, a description of all products transported within the pipeline, and a contingency plan for pipeline emergencies which shall include but not be limited to any reasonable information which the State Fire Marshal may require."

This section reviews the feasibility of pipeline operators notifying local affected fire agencies when their pipeline contents change.

7.1 Questionnaire Development

Initially, each pipeline operator was queried regarding the type of fluids being transported through each or their regulated pipelines. The following table summarizes the number of lines associated with each type of fluid transported. The data indicates that roughly one-third of the pipelines carry some combination of fluids which would require frequent notification of local fire agencies.

Contents Transported	Contents Code	Number of Line Sections
Crude Oil Only	1	165
Light Refined Petroleum Products	2	29
Heavy Refined Petroleum Products	3	170
HVL (e.g., Propane, Butane, LPG, NGL, etc.)	4	7

Combination of Codes 2 and 3	5	163
Any Combination Including HVL's	6	30
Other	7	5
Total Line Sections	-	569

In order to analyze the impact of notifying local fire agencies each time the fluid contents change within a pipeline change, a questionnaire was developed. Four pipeline operators were selected to participate in this portion of the study. The operators were selected to comprise a fairly representative sample of pipeline operators. Data gathered from these operators included:

- frequency of fluid content changes,
- average batch size,
- the pipeline operator's assessment of the impact of a requirement for reporting each fluid contents change to the local fire agencies, and
- the number of Fire Departments which would have to be notified of each change.

7.2 Operators' Responses

The following table summarizes the responses gathered from the pipeline operators.

Company	No. of Line Sections Surveyed	Average Fluid Change Frequency Per Section	Average Batch Size	Average Number of Fire Departments To Contact	Operator Comments
Company 1	3	2/month	412,000 barrels	3	Small number of lines with fairly infrequent product changes. Therefore, the impact would be small. However, the requirement to notify would tax an already burdened staff.
Company 2	3	10/month	19,000 barrels	9	Would need additional personnel to make the "phone calls" to notify the Fire Department. Suggest using a computerized method to transmit data. This would require the Fire Departments to install compatible equipment to receive data.

Company 3	6	18/month	55,000 barrels	3	Operator would require additional staff to make the phone calls and gather data to submit to the Fire Departments. They would prefer a computerized system which would be compatible with the system they now have in place for documenting pipeline transport activity.
Company 4	23	4/month	20,000 barrels	6	Operator feels it is "unrealistic" to require the operators to provide the product change information to the Fire Departments. Considering the number of pipelines which are operated and the number of fluid contents changes occurring, this could amount to a significant task. Additional personnel would be required along with the associated overhead. The operator feels that the Fire Departments would not be able to handle the anticipated flow of data.

7.3 Fire Departments' Responses

The following table presents comments from a representative sample of Fire Departments that were interviewed. The sample was comprised of Fire Departments that had a large amount of pipeline activity within their area. The seven city and county fire departments surveyed all had similar responses concerning pipeline fluid contents notification. *All of the departments surveyed indicated that the data received would not be a useful "day-to-day" tool. They emphasized that knowing the pipeline contents was only important at the time or a leak and/or fire.*

On average, we estimate that each fire department would receive about 5 notifications for each operating pipeline with fluid content changes per month. Naturally, the number of notification calls would vary significantly between various departments. The table below summarizes comments from the fire departments included in our sampling.

Fire Department	Representative	Comments
Long Beach Fire Department	Inspector Hayes Fire Prevention Section (213) 590-2560	*Initial response indicated that the data generated by the notification proposed by the CSFM would not be useful.* More significant would be the ability to handle the flow of data from all of the operators on a daily basis. The Long Beach Fire Dept. currently maintains contingency plans which details all information regarding the pipelines. This information includes a list of all products that would be transported through the pipelines. These contingency plans are updated yearly or sooner if a change occurs. From the Department's perspective, in the event of a leak/rupture/fire, the last priority is to know the specific kind of product that is involved. This would be *after* control and containment (of the "hazardous material") is achieved.
Los Angeles City Fire Department	Floor Captain Operations Control Division (213) 485-6185	*The Operations Control Division would not consider taking this data.* They do not feel it is a necessary part of the day-to-day operations. The flow of information is more useful and timely at the occurrence of an event. Like the Long Beach Fire Dept., The LA City Fire Dept., relies on information contained within contingency plans regarding all pipelines. These plans are maintained continuously.
Los Angeles County Fire Department	Captain Jim Lyall Petroleum Section (213) 887-6660	*The LA County Fire Dept. sees no useful application in receiving this product notification data.* They currently follow the guidelines as stipulated in their county Regulation 20 which requires all operators of pipelines to provide detailed information. This information is updated yearly or sooner if there is a change. This notification approach is viewed as an "overkill".
Kern County Fire Department	Fire Captain's Office (805) 861-2577	*The Kern County Fire Department could not handle the influx of product notification data if mandated for the operators. They also see no "need-to-know" requirement for such data.* Additional personnel would be required to handle such a requirement, considering the high activity rate within the county. The Kern County Fire Department currently maintains an operator list which has a list of contacts and information on the physical details of the pipelines.
San Bernardino County Fire Department	Inspector Mike Huddleston (714) 356-3417	*Initial response indicated that they had no need for such data.* Their opinion was such that the amount of data flow would be overwhelming, requiring additional manpower and support to handle. They see no need for such data on a day-to-day basis, and find the information relevant *only* when there is an occurrence of a leak or other such event. Current Fire Department procedure is considered adequate.
Bakersfield Fire Department	Larry Toler Fire Marshal Fire Safety Control Section (805) 326-3911	*The Bakersfield Fire Department indicated that this data would not be useful or practical on a day-to-day basis.* However, they liked the idea in concept, but felt it would be too burdensome on the operators and on the Fire Department. Too many lines and operators exist within the Fire Department's jurisdiction which would translate into a large volume of notification data. If the data were to be supplied, it could provide the basis for statistical evaluation of pipeline safety regulations imposed by the Fire Department.
Contra Costa County Fire Department	Assistant Fire Chief Argo (415) 447-6611	*The Contra Costa Fire Department indicated that notification data would be useless as an integral part of their day-to-day operations.* Accepting the data is not so much a problem as is the use for the data. They do not see a "need-to-know" on such a routine basis. The need for product information is more useful at the occurrence of an event. They currently maintain contingency plans which have all the operator and pipeline information that is required.

8.0 Conclusions

Based on the results presented for the period from January 1, 1981 through December 31, 1990, the following conclusions have been drawn regarding California's regulated hazardous liquid pipelines. These conclusions have been organized into two subsections. The first includes items which we consider to be major findings, as well as the issues specifically required to be addressed in the study by state statute. The second subsection includes what we consider to be less significant findings.

8.1 Significant Findings

a. Overall Incident Rates

The various criteria used to report hazardous liquid pipeline incidents had a direct effect on the resulting incident rates. The data collected regarding California's incidents was the only completely audited sample available. It resulted in incident rates somewhat higher than those presented in other studies. Using all of the available data, we have estimated the overall incident rates for various pipeline events as follows:

Event	Incident Rate
any size leak	7.1 incidents per 1,000 mile years
damage greater than $5,000	1.3 to 6.2 incidents per 1,000 mile years
damage greater than $50,000	up to 4.4 incidents per 1,000 mile years
any injury, regardless of severity	0.70 injuries per 1,000 mile years
injury requiring hospitalization	0.10 injuries per 1,000 mile years
fatality	0.02 to 0.04 fatalities per 1,000 mile years

b. External Corrosion

External corrosion was by far the largest cause of incidents, representing 59% of the total. Significant differences in external corrosion leak incident rates were found among the following factors:

- Older pipelines had a significantly higher external corrosion incident rate than newer lines.

- Elevated pipeline operating temperature significantly increased the frequency of external corrosion caused leaks.

- Intrastate lines had a much higher external corrosion rate than interstate pipelines. However, the intrastate lines were generally much older and operated at a higher mean operating temperature.

- Non-common carrier lines had a much higher external corrosion rate than common carrier pipelines. But the non-common carrier lines operated at a higher mean operating temperature and were older.

- Crude oil pipelines had a much higher external corrosion rate than petroleum product pipelines. Once again however, crude pipelines had a much higher mean operating temperature and were slightly older.

- Pipelines within standard metropolitan statistical areas (SMSA) had a higher external corrosion incident rate than pipelines in non-SMSA's. Data was not available to further analyze this difference.

- The external corrosion incident rate was significantly less for pipelines greater than 16" in diameter than it was for smaller lines.

- Although a small sample, pipelines without cathodic protection systems had a drastically higher frequency of external corrosion caused leaks than protected lines.

- In some cases, the pipe specification affected external corrosion incident rates.

- Significant external corrosion incident rate differences were found between various pipe coatings. Although pipe age and operating temperature also affected these results, coal tar and asphalt enamel wrapped pipe had an external corrosion incident rate nearly as high as bare pipe. Extruded polyethylene with side extruded butyl coated pipe had the lowest external corrosion rate, one-fifth that of coal tar or asphalt enamel wrapped pipe.

It is likely that many of the older lines included in the study had inadequate cathodic protection, by current standards, during their early years of operation. The regulatory requirements for these lines has increased during their operating life. For instance, although some interstate line regulations date back to 1908, many externally coated interstate lines were not required to be cathodically protected until 1973; many externally coated intrastate lines were not required to be cathodically protected until 1988. Further, intrastate lines operating by gravity or less than 20% SMYS were not required to have cathodic protection until 1991.

c. Railroad Effects

There was virtually no difference between the incident rates for pipelines within 500' of a rail line and pipelines away from rail lines. Further, the average spill size for pipelines within 500' of a rail line was roughly one-third the average spill size for other lines. However, the average damage was much higher for incidents near rail lines.

d. Incident Rate Trends

The data indicates a slightly decreasing incident rate trend during the ten year study period. The ordinary least squares line of best fit indicated that the incident rate was decreasing at the rate of 0.52 incidents per year, per 1,000 mile years of pipeline operation during the study period.

Although the average damage per incident varied widely for each year during the study period, the ordinary least squares line of best fit indicated an increasing trend in average damage per incident during the ten year study period. After normalizing the data to constant 1983 US dollars, the ordinary least squares line of best fit indicated that the average cost per incident increased at the rate of $33,040 per year. The average damage during the study period was $141,000 per incident. However, the median damage was only $7,200 per incident, indicating that a relatively small number of very high damage incidents significantly skewed the average value.

e. Seismic Activity

We anticipate somewhere between 13 and 29 incidents caused by seismic activity on regulated California hazardous liquid pipelines during a future 30 year period. Extrapolating injury and fatality data collected in this study, we would expect seismic activity to cause between one and three injuries and have between a 1 in 6 and 1 in 13 likelihood of causing a fatality during a future 30 year period.

The reader should note that these injury and fatality extrapolations were based on a very limited data sample; their statistical relevance is very limited. Further, for the purposes of this study, data were included in the injury category, regardless of severity; this included injuries which required only minor on-site medical treatment and/or observation. As a result, we expect that any injury data presented herein is conservative, when compared to more typical injury definitions.

f. Block Valve Effectiveness

The median and average block valve spacing on California's regulated hazardous liquid pipelines were 1.39 and 3.12 miles respectively. The median maximum potential drain down length of pipe was 3.4 miles for the incidents with block valve data available. 50% of the spill volumes represented less than 0.75% of the maximum potential drain down volume between adjacent block valves.

We found little or no statistical correlation between spill size and block valve spacing. However, the ordinary least squares line of best fit indicated that reducing block valve spacing would result in a 31 barrel spill volume reduction per mile of block valve spacing reduction (data normalized for 12" nominal diameter pipe). Using this data, if the number of block valves were doubled on California's regulated hazardous liquid pipeline systems by adding 1,909 valves, the average block valve spacing would be reduced from 3.12 miles to 1.76 miles. This would result in only a 13% reduction in overall average spill volumes. We estimate that this would in turn result in only a 1% to 3% reduction in overall average damage values.

We believe that the costs associated with the last barrels spilled are far less than the first few barrels spilled; but we were unable to quantify this relationship. As a result, we performed cost benefit analyses assuming various values for this relationship. The cost benefit analyses regarding adding block valves to California regulated hazardous liquid pipelines, assuming a 10% value for this unknown, are presented below:

	250 Valves	500 Valves	1,000 Valves	1,909 Valves
Estimated Cost (Present Value)	$8,750,000	17,500,000	35,000,000	66,815,000
Estimated Benefit (Present Value)	$402,000	737,000	1,261,000	1,907,000

Cost Benefit Ratio	21.8:1	23.7:1	27.7:1	35.0:1

Similar analyses were performed considering six 12" nominal diameter pipeline segments ranging from one to ten miles long. The cost benefit ratios for the various effectiveness factors for adding an intermediate block valve to these segments are shown below.

Segment Length	10% Factor	25% Factor	50% Factor
1 Mile	384 : 1	153 : 1	76.8 : 1
2 Miles	96.0 : 1	38.4 : 1	19.2 : 1
3 Miles	42.7 : 1	17.1 : 1	8.54 : 1
4 Miles	24.0 : 1	9.60 : 1	4.80 : 1
5 Miles	15.4 : 1	6.15 : 1	3.07 : 1
10 Miles	3.84 : 1	1.54 : 1	0.77 : 1

This data indicates that there may be some justification for additional block valves on very long segments of pipeline. However, natural terrain and other factors affect each situation differently. As a result, each case should be investigated individually.

Several other studies have evaluated the possibility of adding and/or converting to remotely or automatically controlled valves. These studies generally agree that automatically controlled valves are unreliable and are not recommended. They also agreed that any benefits associated with remotely controlled valves could not be realized without effective SCADA systems with leak detection subsystems. One study found a favorable cost benefit ratio for remotely actuated block valves in urban areas. However, this study assumed that remotely controlled valves would result in a 75% reduction in all safety and environmental accident effects. We believe the actual reduction to be much lower than this value. The other studies found cost benefit ratios of 15 - 18:1 for converting existing manually operated block valves to remotely controlled operation.

g. Pipe Age

Pipe age had a significant effect on the resulting overall incident rates. These values ranged from a high of 19.7 incidents per

1,000 mile years for pipelines constructed before 1940, to less than one incident per 1,000 mile years for pipe constructed in the 1980's. All of our statistical analyses indicated a very strong relationship between decade of construction and the resulting incident rates. Most of this variation was caused by differences in the external corrosion incident rate as described earlier.

h. Operating Temperature

There was a direct relationship between normal operating temperature and the resulting external corrosion incident rate. As operating temperature increased, the frequency of external corrosion caused incidents increased as well. We did not find a correlation between operating temperature and other incident causes. All statistical analyses indicated a very strong relationship between operating temperature and external corrosion incident rates.

i. Fire Department Notification

Our survey of pipeline operators and local fire departments yielded a consensus that notifying local affected fire agencies each time pipeline fluid contents changed would not result in significant benefits. The fire departments surveyed indicated that their current programs and contingency plans were adequate to handle foreseen emergencies.

j. Operating Pressure

We did not find a statistical correlation between normal operating pressure and the probability of rupture.

8.2 Less Significant Findings

The less significant study findings are listed below:

- 94% of the injuries and 100% of the fatalities resulted from three incidents (0.58% of the total) during the ten year study period. Each of these incidents had a different cause. Although the number of incidents was too small to draw any meaningful conclusions, it was interesting to note that all of the injuries and fatalities occurred on petroleum product pipelines. (Once again, the reader should be cautioned against drawing any potentially misleading conclusions from this limited data sample.)

- California's high risk pipeline program has been effective in identifying pipelines with a higher than average leak incident rate.

However, the increased hydrotesting requirements placed on these lines did not clearly result in a reduction in incident rates during the study period.

- We were unable to identify a clear relationship between hydrostatic testing frequency and the resulting leak incident rate. It was interesting to find that the most frequently hydrostatically tested pipe had the highest leak incident rate; however, this sample was also the oldest pipe and operated at the highest mean operating temperature.

- 58% of the regulated California hazardous liquid pipelines are capable of being *smart* pigged with little or no modification. 70% of these lines have already been inspected in this manner. Although pipelines which had been internally inspected using *smart* pigs had the lowest overall incident rates, they were also by far the newest.

- Intrastate pipelines had an overall incident rate roughly three times greater than for interstate lines. However, the intrastate lines were on average 13 years older and operated at a mean operating temperature nearly 30°F higher than the interstate lines. The differences between common carrier versus non-common carrier lines had similar results, with the non-common carrier lines having the higher incident rates. In both cases, differences in external corrosion incident rates comprised most of the difference.

- Crude oil pipelines had an overall incident rate of 9.89 incidents per 1,000 mile years. This was over twice as high as the incident rate for product pipelines. However, the operating temperature for the crude lines was 23°F higher. Once again, the differences in the external corrosion rates caused most of the difference.

- The incident rate for pipelines within standard metropolitan statistical areas (SMSA) was over three times higher than for non-SMSA areas. However, the average damage and spill size for incidents within SMSA's was less than one-third of the values for non-SMSA's.

- Pipe diameter had an effect on the external corrosion incident rate. Generally, as pipe diameter increased, the external corrosion rate decreased.

- There was no statistical difference between the leak incident rates for pipelines with sacrificial anodes versus impressed current cathodic protection systems. However, unprotected lines had an external corrosion leak incident rate over five times higher than for protected lines. We did not find a statistical correlation between the frequency of cathodic protection surveys and the external corrosion incident rate.

- 78% of California's regulated hazardous liquid pipe was constructed of ASTM X-Grade material. This class of pipe had the lowest overall leak incident rate (4.13 incidents per 1,000 mile years). However, pipe age and operating temperature differences also affected the results of this investigation.

- Lap welded pipe, which comprised 4% of the total, had an extremely high leak incident rate of 50 incidents per 1,000 mile years. However, this pipe type was also the oldest of the group, with a 1933 mean year of construction.

- There does not appear to be a fluctuation in the frequency of incidents throughout the year.

- 87% of the leaks occurred in the pipe body. 3.1% occurred at valves. 2% were caused by longitudinal weld seam failures. 1.6% were caused by leaks at welded fittings.

- 27% of the incidents resulted in spill volumes of one barrel or less. The median spill size was five barrels. However, the mean spill size of 408 barrels was influenced by a relatively small number of large spills.

9.0 Recommendations

Based on the study findings, we offer the following recommendations regarding California's hazardous liquid pipelines:

a. Industry and/or the California State Fire Marshal should consider implementing programs aimed at reducing external corrosion. These programs could include work regarding:

- external corrosion coating effectiveness,
- cathodic protection system effectiveness,
- refurbishment of deteriorated coatings,
- protection of bare pipelines,
- cathodic protection system interferences in urban areas,
- external corrosion coating and cathodic protection system effectiveness on pipelines operated at high temperatures,
- internal inspection tool effectiveness at identifying externally corroded areas,
- new cathodic protection technologies, etc.

b. Additional regulations should *not* be promulgated regarding pipelines near railroad rights-of-way. We did not find an increased incident rate for lines near rail lines which would necessitate any such regulations.

c. Additional regulations should *not* be promulgated which would require block valves or check valves at established maximum spacings. However, operators should review situations in which they have individual line segments longer than about 10 miles. Depending on local terrain and other factors, they may benefit from additional block valves in some of these situations. Operators should regularly test any block or check valves installed on their systems to verify their integrity.

d. The California State Fire Marshal should review the *high risk* intrastate pipeline program using the results of this study.

We did not find a clear correlation between increased hydrostatic test intervals and the resulting frequency of incidents. As a result, more benefits could likely be obtained by redirecting the monies currently expended on additional hydrostatic testing (estimated at $2,000,000 per year) to other activities aimed at reducing external corrosion leaks (e.g. pipeline replacements, recoating, cathodic protection system upgrades, internal inspections, etc.).

The California Pipeline Safety Act allows operators to apply for hydrostatic test *waivers* from the California State Fire Marshal. Operators should use the existing *waiver* process to propose other activities (e.g. pipe segment replacements, recoating, internal inspections, etc.) in lieu of additional hydrostatic testing on their *high risk* pipelines when such work will likely result in fewer leak incidents.

e. The regular Safety Seminars and other training programs provided by the California State Fire Marshal should be continued. This training is not only valuable to the pipeline operators; it is also useful to public agencies, including the fire service. Further, the Pipeline Safety Advisory Committee is an excellent forum to communicate regularly with pipeline operators and the fire service; it should be continued.

f. An abbreviated report, covering the items included in Section 4.0 of this study, should be prepared every 5 to 10 years. The goals of this study should be to identify incident rate trends, review current regulation effectiveness, and recommend change. To this end, the California State Fire Marshal should require the pipeline operators to submit leak data similar to that collected in this study.

The California Government Code §51018 should be revised to require reporting in the selected format to the California State Fire Marshal. The present code language should also be revised to clarify the requirement for reporting leaks which occur during hydrostatic testing.

g. Future legislation aimed at reducing injuries and fatalities should consider the differences between crude oil and petroleum product pipelines. Any more stringent requirements for product pipelines should also consider the differences in risk between various petroleum products (e.g. diesel versus gasoline).

h. The permitting process should be streamlined to the greatest extent possible for pipeline replacement projects. Every effort should be made to remove obstacles and to encourage pipeline operators to replace older pipelines with high leak-history. The possibility of reduced franchise fees for replacement lines should also be considered to increase the incentives for owners to replace older sections of high leak-history pipe.

There have been several recent incidents in which pipeline replacement projects have been delayed because of local permitting problems. Further, perceived federal, state and local permitting costs and problems have forced some pipeline operators to shy away from replacement projects. This can result in two possibilities: the operator continues to operate the relatively high incident rate pipe, or the volumes are diverted to other less safe means of transportation (e.g. tanker trucks, etc.).

i. We believe that the increased efforts aimed at reducing third party damage, especially the one-call system, have been very successful and should be continued.

10.0 Bibliography

Andersen, Terje and Asbjorn Misund. "Pipeline Reliability: An Investigation of Pipeline Failure Characteristics and Analysis of Pipeline Failure Rates For Submarine and Cross Country Pipelines." Journal of Petroleum Technology. April 1983, 709-717.

Eiber, R. J. , D. J. Jones and G. S. Kramer. "Outside Force Causes Most Natural Gas Pipeline Failures." Oil and Gas Journal, March 16, 1987, pp. 52-57.

Jones, Dana J., et. al. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines 1970 through June 1984. American Gas Association, March 1986.

Jones, Dana J. and R. J. Eiber. An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines June 1984 through 1989. American Gas Association, October 1990.

Lyons, D., et. al. Performance of Oil Industry Cross Country Pipelines in Western Europe, Statistical Summary of Reported Spillages - 1981 through 1989. Brussels: CONCAWE.

Martinsen, W. E. and J. B. Cornwell. "Use and Misuse of Historical Pipeline Failure Rate Data." Proceedings of the 1991 Pipeline Risk Assessment, Rehabilitation and Repair Conference, Gulf Publishing, 1991.

National Science Foundation. Early Post-Earthquake Damage Detection for Underground Lifelines.

National Transportation Safety Board. Special Study of Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown. December 1970.

National Transportation Safety Board. Pipeline Accident Report, Four Corners Pipe Line Company Pipeline Rupture and Fire, Long Beach, California, December 1, 1980. August 1981.

National Transportation Safety Board. Railroad Accident Report, Derailment of Southern Pacific Transportation Company Freight Train on May 12, 1989 and Subsequent Rupture of Calnev Petroleum Pipeline on May 25, 1989 - San Bernardino, California. June 1990.

O. Rourke, T., el. al. "Lifeline and Geotechnical Aspects of the 1989 Loma Prieta Earthquake." Proceedings of the 2nd International Conference on Recent Advances in Geotechnical Earthquake Engineering and Soil Dynamics, Saint Louis, Missouri. March 1991.

Rusin, Michael. Pipeline Transport of Highly Volatile Liquids: A Cost-Benefit Analysis of Proposed Safety Regulation of Valve Spacing and Operation. Washington, D.C. American Petroleum Institute, 1979.

Rusin, Michael and Evi Savvides-Gellerson. The Safety of Interstate Liquid Pipelines: An Evaluation of Present Levels and Proposals for Change, Research Study #040. Washington, D.C.: American Petroleum Institute, 1987.

Tiratsoo, J. N. H, ed. Pipelines and the Environment. United Kingdom: Pipes and Pipelines International, 1984.

Toppozada, T. "Earthquake Magnitude as a Function of Intensity Data in California and Western Nevada." Bulletin Seismological Society of America, Vol. 65, No. 5, (October 1975), pp 1223-38.

Transportation Research Board, National Research Council. Special Report 219, Pipelines and Public Safety, Damage Prevention, Land Use, and Emergency Preparedness. 1988.

U.S. Department of Transportation. An Examination of the Feasibility of Regulating Excavators. October 1990.

U.S. Department of Transportation, Research and Special Programs Administration. Emergency Flow Restricting Devices Study. March 1991.

U.S. Department of Transportation, Research and Special Programs Administration. Transportation Safety Information Report 1988 Annual Summary. December 1989.

U.S. Department of Transportation, Research and Special Programs Administration. National Transportation Statistics - Annual Report. July 1990.

U.S. Department of Transportation, Research and Special Programs Administration. Annual Report on Pipeline Safety - Calendar Years 1981 through 1990.

U.S. Department of Transportation, Office of Pipeline Safety. Rapid Shutdown of Failed Pipeline Systems and Limiting of Pressure to Prevent Pipeline Failure Due To Overpressure. October 1974.

U.S. Department of Transportation, Office of Pipeline Safety. Transportation of Highly Volatile, Toxic, or Corrosive Liquids By Pipeline. February 1976

U.S. Geological Survey. United States Earthquakes, 1982 - U.S. Geological Survey Bulletin 1655. 1982.

U.S. Geological Survey. Preliminary Isoseismal Map for the Santa Cruz (Loma Prieta), California Earthquake of October 18, 1989 - U.S. Geological Survey Open File Report 90-18. 1990.

U.S. Geological Survey. The San Andreas Fault System, California - U.S. Geological Survey Professional Paper 1515.

Exhibit 1
Acknowledgements

A. J. Adams
Texaco Refining and Marketing

Fred Adams
Chevron Pipe Line Company

Michael A. Allen
Martinez Terminals, Ltd.

David Andries
Calnev Pipe Line Company

Steve Appel
Pennzoil Products Company

Assistant Fire Chief Argo
Contra Costa County Fire Department

M. H. Asghar
Refiners Marketing Company

Paul Bauer
Unocal Corporation

Michael Bennett
Pennzoil Products

H. K. Bishop
San Diego Gas and Electric Company

Jim Blaser
Petrolane, Inc.

Clayton D. Bowers
Pacific Gas and Electric Company

Myles Butler
Pacific Refining Company

Steve Cadenazzi
Pacific Refining Company

Chris Carpenter
All American Pipeline Company

David Chapman
Texaco Trading and Transportation

Tom Collins
Chevron Pipe Line Company

Keith Darney
Powerine Oil Company

Dirk Cavanaugh
Texaco Trading and Transportation, Inc.

John F. Dayton, III
Southern California Edison

Rudy Deman
Wickland Oil Company

Roger S. Diaz
Pacific Gas and Electric Company

J. P. Dodson
Management Engineering Association

Barry D. Emeneger
Unocal Corporation

Jerry Engelhardt
Santa Fe Pacific Pipeline

Mike Ewing
Hood Corporation

Paul Fager
Pacific Refining Company

Burl A. Foster
BP North America Petroleum, Inc.

Greg Gamble
Unocal Corporation

Al Garcia
Pacific Gas and Electric Company

Jerry Goehring
Gatron

Bill Goings
Southern California Edison Company

Rick Goracy
Fletcher Oil and Refining Company

Andrew Grant
Aircraft Service International, Inc.

Frank Green
Paramount Petroleum Corporation

Charles J. Greenway
Chevron International Oil Company, Inc.

D. R. Hahlbeck
Chevron U.S.A., Inc.

Wayne Hall
Petro-Diamond Incorporated

Al E. Hamilton
Wilmington Liquid Bulk Terminals

Carl D. Harrington
Golden Gate Ferry

Inspector Hayes
Long Beach Fire Department

Roy Hearon
Paramount Petroleum Corporation

Don Herman
Shell Pipe Line Corporation

Gary Hohnstein
Texaco Trading and Transportation Inc.

Mike Huddleston
San Bernardino County Fire Department

David P. Hylton
Chevron Corporation

Steve Ito
Tidelands Oil Production Company

Ron James
Unocal Corporation

Tom Jensen
Santa Fe Pacific Pipeline Company

Bobby O. Jones
Pacific Gas and Electric Company

Richard Kelley
Texaco Trading and Transportation, Inc.

Pat Kennedy
Petro-Diamond Terminal Company

Paul W. King
Public Utilities Commission

Matt Krubski
Unocal Corporation

Charles Lankford
Witco Corporation, Golden Bear Division

Raymond Lencioni
Koch Oil Company

Elizabeth Liske
Chevron Pipe Line Company

Randal Livingston
Pacific Gas and Electric Company

Gene Loomis
Enron Oil Trading and Transportation

Victor Lopez
Saint James Oil Corporation

Jim Lyall
Los Angeles County Fire Department

Mike Lyons
Pacific Gas and Electric Company

Hank March
Chevron U.S.A., Inc.

Ted Meadows
Ultramar, Inc.

R. D. McKenna
Pacific Gas and Electric Company

Ted Meadows
Ultramar, Inc.

Thomas B. Meadows, III
OXY U.S.A., Inc.

Donald L. Melchiori
Chevron U.S.A., Inc.

Kathie R. Miller
Mobil Oil Corporation

Judith Moorad
Shell Refinery

David W. Moore
Four Corners Pipe Line Company

Dale A. Murdock
Pacific Gas and Electric Company

Bud Nelson
Tenco Services

R. T. Nelson
Pacific Gas and Electric Company

Kenneth M. Oldmixon
Unocal Corporation

Rick Osborn
Ultramar, Inc.

John F. Pavano
Texaco Refining and Marketing, Inc.

Peter W. Prather
Chevron U.S.A., Inc.

Kevin J. Redford
GATX Terminal Corporation

D. D. Richardson
Pacific Gas and Electric Company

P. E. Rigney
Pacific Gas and Electric Company

Charles D. Roncelli
Pacific Gas and Electric Company

Lindley Ruddick
Dow Chemical U.S.A.

Edwin Sato
Powerine Oil Company

Gilbert C. Schutza
Enron Oil Trading and Transportation

James W. Simon
Los Angeles Department of Water and Power

John R. Sisk
Mobil Oil Corporation

Dick Sloan
Encoat Coatings Company (Retired)

Milo Soto
Chemoil Refining Corporation

Brad L. Standley
Santa Fe Energy Resources, Inc.

C. Stewart
Lomita Gasoline Company

Larry Sullivan
Western Fuel Oil

Bob Sutherland
Chevron Pipe Line Company

Susan Tobias
Texaco Lubricants Company

Larry Toler
Bakersfield Fire Department

Theodore J. Ursino
Pacific Gas and Electric Company

A. Van Os
Lomita Gasoline Company

Steve Van Winkle
Unocal Corporation

Gerald E. Wagner
Golden West Refining Company

E. Tom Webb
Pacific Gas and Electric Company

Kim R. Will
American President Lines

James H. Wills
Tidelands Oil Production Company

Harold L. Witcher
Kern Oil and Refining Company

Robert L. Wetzel
Santa Fe Pacific Pipelines

Lamar White
Unocal Corporation

Clarence Wilson
Tenco Services, Inc.

Jack Woycheese
Gage-Babcock and Associates

Clark S. Wriggly
Tosco Refinery